ASSESSMENT OF THE IMPACTS OF DEMAND CURTAILMENTS IN THE *DAM*s: ISSUES IN AND PROPOSED MODIFICATIONS OF *FERC* ORDER NO. 745

BY

ISAAC CASTILLO

THESIS

Submitted in partial fulfillment of the requirements
for the degree of Master of Science in Electrical and Computer Engineering
in the Graduate College of the
University of Illinois at Urbana-Champaign, 2012

Urbana, Illinois

Adviser:

Professor George Gross

ABSTRACT

The Federal Energy Regulatory Commission (*FERC*), in its initiative to incentivize demand response resources (*DRR*s) to participate in the day-ahead markets (*DAM*s), enacted Order No. 745. The Order mandated each *ISO*/*RTO* to perform a monthly cost-effectiveness test, the so-called net benefits test (*NBT*), that determines the monthly threshold price that serves as the economic signal for the dispatch of *DRR*s. The determination of the threshold price without explicit consideration of the grid and its associated constraints prompted the motivation for our investigation. Analytical considerations of the issues were accompanied by extensive numerical studies based on simulation. In our studies, we identify the two key unintended consequences emanating from the *DRR* participation in the *DAM*s. One is the existence of instances where the dispatch of *DRR*s increases the purchase payments of loads not participating in curtailment provision so that those buyers are worse off due to the *DRR* demand curtailments presence in the *DAM*s. The second set of unintended consequences consists of the cases where the participation of *DRR*s results in higher prices to their remaining loads under the *FERC* compensation rules. The *NBT* fails to test for these unintended consequences and based on our simulations studies, such events may occur frequently.

In light of the results of these investigations, we propose specific modifications to the *NBT*. The modifications are in three principal areas – data usage, explicit consideration of transmission system in the determination of the threshold price and an additional test to guarantee that no buyer is worse off in the post-curtailment state than in the pre-curtailment state. We propose to limit the data to on-peak *LMP*s instead of the representative offer curve data based on data from all the hours of the month. We propose the replacement of the system-wide threshold price by node-specific threshold prices at each node to explicitly account for transmission considerations. To ensure that no post-curtailment load is worse off than in the pre-curtailment conditions, we propose the introduction of a simple test to verify that this criterion is met. The proposed modifications result in nodal threshold prices and this explicit transmission consideration is effective in avoiding the issues we identified with the *FERC NBT*. We illustrate the ability of the proposed modifications to address these issues by presenting a representative sample of simulation studies from the testing we performed. The results of the testing we performed indicate that the instances of higher post-curtailment purchase payment are reduced by at least an order of magnitude and in each case every node in the system is assured that it is not worse off due to demand curtailments. The proposed modifications result in an important reduction in the unintended consequences due to demand response participation.

To my parents

ACKNOWLEDGMENTS

I would like thank my adviser, Professor George Gross, for his guidance and support throughout the course of my studies at the University of Illinois of Illinois at Urbana-Champaign. His unconditional willingness to provide help for my work is deeply appreciated.

The collaboration of my colleague and friend Kai Van Horn was essential for the completion of this work. I am grateful for his valuable input because it made me overcome many of the research problems I encountered. I would also like to thank all the students and staff of the Power and Energy Systems Group.

I would like to thank Rick Gilkey and the folks at Customized Energy Solutions for my experience as an intern. The time I spent at the company made me gain more insight into the electricity markets.

I am deeply indebted to my parents, Isaac Castillo and Xenia Rios, for their constant support and encouragement. Finally, I thank my soon-to-be wife Annette Christine for her kindness and advice during my stay in the United States of America.

TABLE OF CONTENTS

LIST OF FIGURES

LIST OF TABLES

LIST OF ABBREVIATIONS

DRR	Demand Response Resource
FERC	Federal Energy Regulatory Commission
ISO	Independent System Operator
RTO	Regional Transmission Organization
IGO	Independent Grid Operator
DAM	Day-Ahead Market
DSM	Demand-Side Management
CSP	Curtailment Service Provider
LMP	Locational Marginal Price
SMP	System Marginal Price
NBT	Net Benefits Test
ROC	Representative Offer Curve
AROC	Adjusted Representative Offer Curve
ISO-NE	Independent System Operator of New England
MISO	Midwest Independent System Operator
RLMPC	Representative Locational Marginal Price Curve
LTP	Locational Threshold Price

CHAPTER 1

INTRODUCTION

In this chapter, we lay out the contents of this thesis. Or focus is the study of the impacts of demand curtailments in the electricity markets under current regulatory initiatives. We start by discussing the motivation and background of our research to set the stage of the work presented in the thesis. We provide a brief summary of the key regulatory initiatives that have led to the current rules and we also review the state-of-the-art in the current demand response compensation schemes.

1.1 Motivation and Background

Growing environmental concerns, the need of energy independence and the push for sustainability are the key drivers of electricity-market policies. Renewable energy (*RE*), large-scale storage (*LSE*) and demand response (*DR*) are technologies the Federal Energy Regulatory Commission (*FERC*) is keen on implementing. The *FERC*, as the governmental agency in charge of regulating the wholesale sales of electricity, oversees the energy markets run by the Independent System Operators (*ISO*) and the Regional Transmission Organization (*RTO*). The *ISO*s and *RTO*s are non-profit organizations responsible for administering the electricity markets within one or multiple regions. We group all the *ISO*s and *RTO*s in the term independent grid operator (*IGO*) to facilitate the discussion. As a result of the intermittency effects associated with *RE* generation and the slow penetration of *LSE* technologies, investors, regulators and system operators are pushing towards the demand-side to maintain the reliable operation of the power systems. The demand-side can participate in the electricity markets in the form of the so-called demand response of the consumers. Demand response consists in a reduction in electricity usage by the consumer in response to a price, emergency or reliability signal. The responsive consumers get compensated every time they curtail their electricity usage. We refer to the loads that have the capability of providing load reductions as demand response resources (*DRR*s).

Before the restructuring of the electricity industry, demand response activities were grouped into the term demand-side management (*DSM*). *DSM* activities were tools the integrated utilities used to attain a desired load shape and were traditionally divided into six objectives: peak clipping, valley filling, load shifting, flexible load shape, strategic conservation and strategic load growth. The first four represent objectives to alter the electricity usage at targeted times and are nowadays all incorporated into the term demand response. The integrated utilities managed all the *DSM* activities until the advent of the restructuring of the electricity industry.

Demand response increased its prominence when in 2005, the United States Senate passed Energy Policy Act of 2005 (Epact 2005), a bill with several provisions for electricity markets [1]. The Epact 2005 mandated the *FERC* to produce a comprehensive study of demand response in the United States. As a result of this study the Assessment on Demand Response and Advanced Metering (*DR&AM*) was published in 2006 [2]. The *DR&AM* recognized the benefits of demand response in the electricity markets and made some recommendations. The *FERC* recommended to:

(i) explore how to better accommodate demand response in wholesale markets;

(ii) explore how to coordinate with utilities, state commissions and other interested parties on demand response in wholesale and retail markets; and

(iii) consider specific proposals for compatible regulatory approaches, including how to eliminate regulatory barriers to improved participation in demand response, peak reduction and critical peak pricing programs.

By implementing these recommendations, demand response became part of *FERC*'s jurisdiction. Furthermore, the Energy Independence and Security Act of 2007 (EIAct 2007) mandated the *FERC* to conduct a national assessment on demand response. This resulted in the publication of A National Assessment of Demand Response Potential (*NADRP*). *NADRP* identified the barriers to demand response in the electricity market: lack of a direct connection between wholesale electricity prices, ineffective demand response program design, lack of customer awareness and education, and concern over environmental impacts. The *NADRP* also estimated the nationwide demand response potential in 5 and 10 year horizons on a state-by-state basis, and how much of the potential can be achieved within those time horizons; and the report includes specific policy recommendations for developing incentives and for overcoming the above-mentioned barriers. According to the NADRP, the 2019 peak load in the United States can be reduced by as much as 150 GW, compared to the business-as-usual scenario.

In order to overcome these barriers, the *FERC* created a new type of market player. In Order No. 719, the *FERC* defined curtailment service providers (*CSP*s) as demand response aggregators [3]. These *CSP*s are entities that enroll customers that are willing to reduce load, into large load aggregations. Order No. 719 also amended previous *FERC* regulations to treat demand response comparably to other resources. To accomplish this, the FERC mandated the *IGO*s to:

(i) accept demand offers from demand response resources,

(ii) eliminate, during emergencies, certain charges to buyers in the energy market for voluntarily reducing demand,

(iii) permit *CSP*s to offer demand response on behalf of retail customers directly in to the markets.

Although the changes introduced by Order No. 719 were significant, in 2011 the *FERC* believed that these demand reductions still encountered barriers in the electricity markets. This is why in 2011 the *FERC* enacted Order No. 745. In Order No. 745 the *FERC* mandated all of the *IGO*s to compensate all of the demand response resources that clear in the energy market at the locational marginal price (*LMP*) when used to balance supply and demand. The *FERC* also mandated all *IGO*s to conduct a monthly cost-effectiveness test that will be used as a metric to judge when demand curtailments are allowed in the energy markets. This cost-effectiveness metric is a system-wide threshold price that is calculated using the so-called net benefits test (*NBT*). The *NBT* is a monthly procedure that uses historical offer data to determine the price at which a demand curtailment results in benefits to the system. Each *IGO* must follow *FERC*'s guidelines to run the *NBT* on a monthly basis.

1.2 Review of the State of the Art on the Impacts of *FERC* Order No. 745

The question of how much a retail customer should be paid for curtailing its demand has been the subject of considerable debate. The nearly 3800 pages of comments the *FERC* received after the publication of the notice of proposed rulemaking (*NOPR*) that eventually resulted in Order No. 745, document the various opinions on the issue [4],[5],[6]. Also, the dissenting opinion of *FERC* Commissioner Moeller in Order No. 745, in which, he detailed the rationale for his opposition to the rule, provides a summary of some of the key issues of those who do not support the thrust of the ruling [7, pp. 102]. In this section, we provide a brief summary of the literature and the comments regarding demand response compensation under Order No. 745.

It is widely accepted that the implementation of demand response in the electricity markets can provide substantial benefits including improvement in the elasticity of the demand curve, reduction in the price paid by the loads, reductions of environmental emissions, betterment of the grid's reliability, and reduction in the costs of developing addition peaking generation. Although, all agree that these benefits are attainable, there exists a difference in opinion on the way *DRRs* should be compensated for the curtailment services provided.

The standardization of a demand response compensation scheme was the issue the *FERC* faced when developing Order No. 745. During the process that led to the decision that *DRRs* are paid at the *LMP*, various opinions had to be taken into account. *FERC*'s decision that demand and supply-side resources can substitute each other was based on the premise that "*in balancing supply and demand, a one megawatt reduction in demand is equivalent to a one megawatt increase in energy for purposes of meeting load requirements and maintaining a reliable electric system*" [4, pp. 15]. Furthermore, under Order No. 745 *DRRs* are only to be dispatched when the cost-effectiveness conditions of the *NBT* are met. The *FERC* sought and received a large volume of comments on the comparability of demand response and generation resources, the compensation proposal, and the implementation of the *NBT*.

When asked to submit comments on *FERC* Order No. 745, one view adopted by some is that "*demand response (DR) is in all essential respects economically equivalent to supply response; and that economic efficiency requires, as the NOPR recognizes, that is should be rewarded the same LMP that clears the market*" [6, pp. 24]. On the other hand, other comments assert that *DRR*s are not equivalent to generation resources and that paying the *LMP*, without some offset for some portion of the retail rate, for demand curtailments will discriminate against generation resources in the short run and will overcompensate demand response [7, pp. 21].

In support of their thesis, those who hold the view of the equivalency between *DRR*s and generation resources posit that *DRR*s provide a superior service to generation because they could provide a quicker response than traditional generation, reduce environmental emissions and, in addition, mitigate the need for the investment in new generation plants [5], [6]. Furthermore, they claim that since electricity prices fail to internalize environmental externalities, such as toxic air pollution, greenhouse gas emissions, and land and water use impacts, demand response should be compensated as mandated by Order No. 745. They extend their argument by saying that since the impacts of these externalities are especially acute at peak hours, demand response curtailments at these periods of time avoids the use of peaking plants such as gas turbines. Although there is much truth to this claim, it is no longer valid once the *DRRs* resort to behind-the-meter generation. We refer to behind-the-meter generation (*BMG*) as a generation unit that serves a load and is not interconnected with the electricity grid. If a large percentage of demand resources use *BMG* to offer load curtailments to the *IGO*, then this type of demand response does not contribute to the reduction of environmental emissions. Also, air pollution in cities and noise levels are a main problem with *BMG* since more commercial buildings are participating in demand response.

Those who oppose the equivalency of *DRR*s with generation resources hold that *DRRs* should be compensated at the *LMP* minus the retail rate (*RR*) [8], [9], [10]. The rationale behind this notion is that paying the full *LMP* fails to take into account the savings associated with demand response and results in overcompensation for the *DRR*. Indeed, some argue that paying demand response at the *LMP* represents a double payment and that it may lead to inefficient demand response [11]. Ultimately, the *FERC* adopted the view that demand response is *equivalent* to generation when used to balance supply and demand.

In addition to the equivalence of demand response and generation resources and the appropriate compensation level for demand response resources, the utilization of the *NBT* created many comments after the publication of the *NOPR* related to Order No. 745. According to the *FERC*, the *NBT* prevents the dispatch of demand response resources when it results in an increased cost per unit to the load and that ensures that the benefits of dispatching *DRRs* exceed the costs. One of the main issues raised by the *NBT* is that it focuses solely on the benefits to consumers. The *NBT* judges cost-effectiveness from the point of view of the benefits to one group of market participants and does not consider the societal cost of meeting demand. The Market Surveillance Committee of the *CAISO* (*MSCCA*), in its comments on the *NBT*, stated that "*this is a large departure from the FERC market design principle, which is nondiscriminatory market access to promote maximum market efficiency, as measured by the usual market efficiency metric of producer plus consumer surplus.*" Furthermore, the *MSCCA* and *NYISO* stated that paying *DRRs* at the *LMP* mines the *RR* avoids the need of a net benefits test [12].

One issue not widely discussed in the literature is the non-regional nature of the *NBT*. Since the *NBT* is based purely on offer-curve analysis and does not take into consideration the power system network, it ignores one of the key components of the price of electricity: congestion. By ignoring the power system constraints, the *NBT* assumes that the network runs ideally. The *NBT* also assumes that when a demand curtailment is made, all the consumers in the system benefit. These assumptions may be too much of a leap of faith and need to be investigated further. The reports discussed in this literature review use economic methodologies to analyze the possible impacts of Order No.

745. Although very relevant and insightful, these reports ignore the operational aspects of the power system.

1.3 Scope and Nature of the Contributions of the Thesis

In this report, we focus on the study of the impacts of demand curtailments in the *ISO*-run *DAM*s. We explicitly take into account the requirements of the *FERC* Order No. 745 in the transmission constrained electricity market model. Using representative simulation studies we analyze the impacts of demand curtailments in the *DAM*s. We identify they key unintended consequences that result from demand response: the existence of instances where the dispatch of *DRR*s increases the purchase payments and the fact that some market participants are worse off due to the demand curtailments. We also investigate and determine the causal factors of these issues.

In light of the identified unintended consequences and the identification of the causal factors, we propose modifications to the *NBT* that keep its spirit intact and do not change the nature of the procedure. We propose to use *LMP* data instead of offer data to determine the monthly threshold price. Our proposed modifications result in nodal thresholds. To ensure that no buyer is worse off due to demand curtailments, we propose to guarantee that this condition is met.

1.4 Thesis Outline

The remainder of the thesis is organized in the following manner. In Chapter 2, we provide a detailed description of *NBT* and its applications in the clearing of the day-ahead markets. We start by describing the requirements mandated by the *FERC* and then proceed to explain the *NBT* in economic terms. In this chapter, we also provide the entire procedure *FERC* mandates the *IGO*s to use in order to calculate the monthly threshold price. In Chapter 3, we discuss the unintended consequences associated with the dispatch of *DRR*s under the current rules. In Chapter 4, we provide the modifications to the *NBT* that we developed. In Chapter 5, we provide the results and our analyses of the simulation studies. We provide our concluding remarks and suggestions for future research in Chapter 6. In Appendix A, we describe the test system used to run all of the simulation studies presented in the thesis.

CHAPTER 2

THE NET BENEFITS TEST PROCEDURE

Under *FERC* Order No. 745, the clearing of a *DRR* in the *DAM*s depends on the monthly threshold price, as determined by the implementation of the net benefits test (*NBT*). The *NBT*'s goal is to determine a cost-effectiveness condition that restricts participation of *DRR*s to only those hours in which the benefits of the buyers due to the lower electricity prices outweigh the payments to the *DRR*s. Whenever the *NBT* conditions are met, the *DRR*s are compensated at the *LMP* at the node at which the curtailment is provided. In this chapter we provide the description of the *NBT* and we formulate the modified *DAM* clearing optimal power flow (*OPF)* problem with the *NBT* included. In Section 2.1, we provide a discussion of the *FERC* requirements for the *NBT*. In Section 2.2, we describe all the steps needed to determine the monthly threshold price. We devote Section 2.3 to formulate the inclusion of the *NBT* determination in the clearing of the *DAM*s with *DRR* load curtailment.

2.1 *FERC NBT* Assessment

In order to determine the hours during which demand-curtailment offers are considered in the clearing of the *DAM*s, each *IGO* is mandated under Order No. 745 to routinely conduct the *NBT* each month so as to determine the monthly threshold to ensure the cost-effectiveness of such curtailment offers. We start with a review of the *NBT* requirements, continue with a discussion of the degrees of freedom available to the *IGO*s and provide an economic interpretation of the *NBT*.

According to *FERC* Order No. 745, each *DRR* is compensated at the *LMP* at the node at which its load curtailment is provided whenever the *DRR* offer is used by the *IGO* to balance supply and demand and the specified *FERC* conditions are met [7]. The *NBT* mechanism is the *FERC*'s procedure to ensure that the *IGO* uses cost-effective dispatch of the *DRRs*. The *NBT*, in essence, compares the total benefits of dispatching *DRRs* to the total payments of the buyers in compensation for the demand curtailment provision. The total benefits are the net savings of the post-*DRR* curtailment loads brought about by the reduced hourly electricity prices due to the curtailments.

Each *IGO* calculates using a representative offer curve based on data from the same month of the preceding year, the price at which the dispatch of *DRR*s becomes cost-effective. Moreover, Order No. 745 mandates the *IGO*s to comply with the following requirements:

- The *IGO* must publish the monthly threshold price on the 15th day of the preceding month.
- The determination of the monthly threshold price requires the use of a representative offer curve for the entire month constructed from the offer data submitted for that month in the previous year; the determination may incorporate any changes in fuel prices and resource availability and may use numerical smoothing of the representative offer curve.

Order No. 745 also provides certain degrees of freedom in the implementation of the *NBT* by each *IGO* in terms of the construction of the adjusted representative curve due to

- the ability to adjust for changes in fuel prices and resource availability, and
- the ability to use a smoothing technique to construct a continuous curve.

Such degrees of freedom allow the *IGO* to construct the adjusted representative curve in non-unique ways due to the multiple curves that may result. There exist no clear metrics to assess whether a particular curve is better than another possible curve. As such, the selection of the adjusted representative offer curve is arbitrary since the adjusted curve is a function of the resolution used in the offer data, the fuel price indices adopted for measuring the changes and the smoothing technique deployed [13]-[17].

We provide an economic interpretation of the effects of the *NBT* determination by considering a single hourly *DAM*. The analysis of the *NBT* in this section is based on the assumption used by *FERC* Order No. 745 that there are no transmission constraints in the grid and considers the transmission unconstrained market clearing problem (*TUMCP*). We represent the market corresponding to the snapshot of the system for that hour.

In the *TUMCP*, the *IGO* uses the submitted generation offers by the sellers to construct the supply curve by sorting them in order of increasing prices. Similarly, the *IGO* constructs the demand curve by sorting the buyers' demand bids in order of decreasing prices. In Fig. 2.1, we illustrate graphically the clearing of a *DAM* using supply-side offers and the demand-side bids. The intersection of the supply and demand curves $\left([\ell']^{*},[\lambda']^{*}\right)$ determines the market equilibrium with $[\ell']^{*}$ as the total cleared demand and $[\lambda']^{*}$ as the system marginal price (*SMP*). Each seller (buyer) receives (pays) the *SMP* for each MWh sold (bought). We next include the effects of demand curtailments in the market equilibrium in the *DAM*.

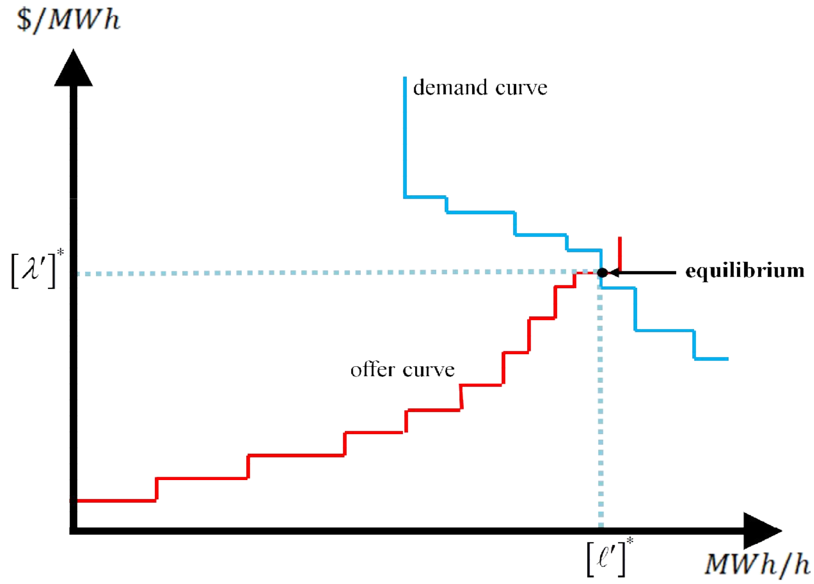

Figure 2.1: Equilibrium of an hourly *DAM*

We consider the dispatch of a *DRR* curtailment that reduces the system load demand by $\Delta\ell$. Such a change essentially produces a shift in the demand curve to the left. This shift results in a modified market equilibrium $\left([\ell]^*,[\lambda]^*\right)$, where $[\ell]^*$ is the modified cleared demand and $[\lambda]^*$ is the post-curtailment *SMP* as shown in Fig. 2.2. Since the modified cleared demand $[\ell]^*$ (where $[\ell]^* \triangleq [\ell']^* - \Delta\ell$) is necessarily lower than the demand without *DRR*s, the monotonic non-decreasing nature of the supply curve implies that $[\lambda]^* \leq [\lambda']^*$. With the participation of the *DRRs* in the *DAM*, the post-curtailment *SMP*, $[\lambda]^*$, is used to pay/buy each MWh including the curtailment provided by the

DRR. As such, the social, consumer and producer surpluses may change with respect to the case with no *DRR* participation.

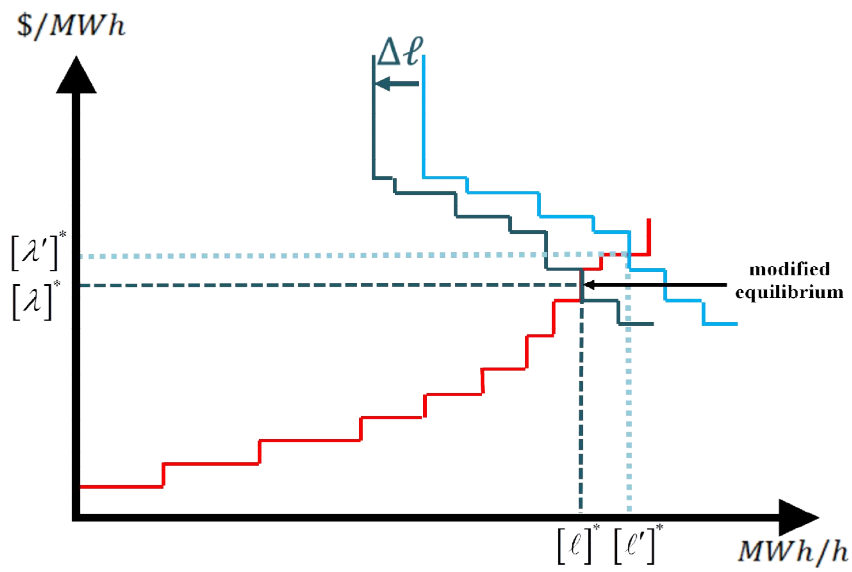

Figure 2.2: Modified market equilibrium with demand curtailments

Next, we examine the repercussions of the post-curtailment supply-demand curve equilibrium. Consider Fig 2.3 areas A_λ and A_ℓ. For $[\lambda]^* \leq [\lambda']^*$, A_λ represents part of the reduction in the producer surplus with respect to the pre-curtailment equilibrium. This reduction results in potential savings for the post-curtailment loads. As a result, these loads may obtain additional benefits of using electricity at the lower price and so their consumer surplus may increase relative to the pre-*DRR* curtailment situation. The producers whose post-curtailment energy is sold in the *DAM* are compensated at the post-curtailment *SMP* $[\lambda]^*$ and so their producer surplus is reduced. Also, some sellers may not be able to sell at the post-curtailment equilibrium. The area A_λ is $\left([\lambda']^* - [\lambda]^*\right)\cdot[\ell]^*$ represents the total reduction in the payments to the supply side by the post-curtailment load in the post-curtailment market. This is simply a transfer of some of the producer surplus to those consumers whose loads are not curtailed. However, we have so far not considered any payment to incentivize the *DRR* to provide curtailment.

Next, we consider the area A_ℓ. We view A_ℓ to represent the total value of dispatching the *DRR*s since under the *FERC* Order No. 745 all the *DRR*s whose offers clear in the *DAM* are compensated at the post-curtailment *SMP*. Thus, the area $A_\ell, \left([\ell']^* - [\ell]^*\right)\cdot[\lambda]^*$ constitutes the total payments to the *DRR* for the load curtailment. Since this payment must be made by the consumers that have post-curtailment loads, in effect, this represents a reduction in the benefits [18]-[20]. The *NBT* determines the point in the representative offer curve where the benefits of dispatching demand curtailments are exactly equal to the payments to the providers of these curtailments. In other words, the threshold value in our discussion corresponds to the value $\left[\hat{\lambda}\right]^*$, where $A_\lambda = A_\ell$.

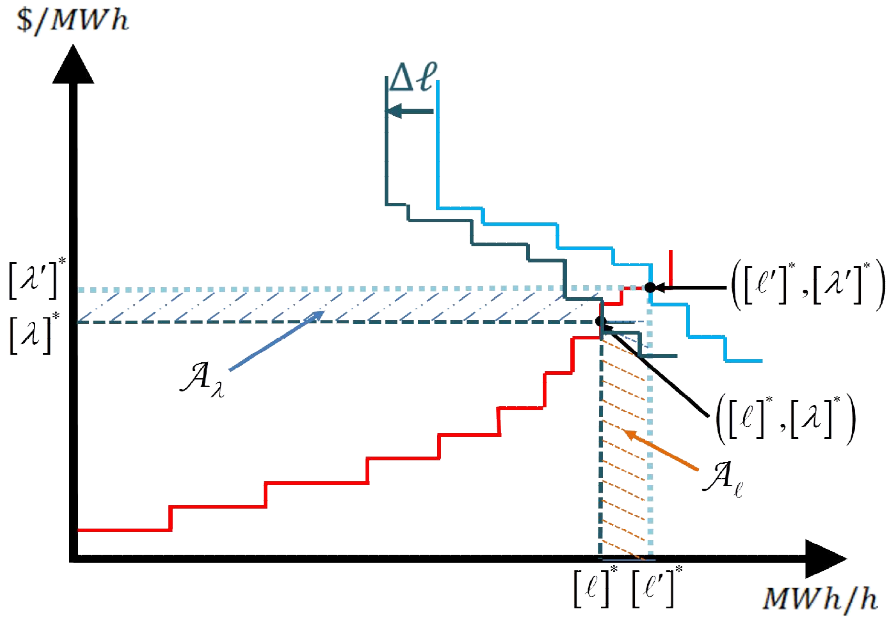

Figure 2.3: Demand curtailments benefits and payments to *DRR*s

2.2 The Threshold Price Determination

We devote this section to describe the procedure an *IGO* is mandated to implement in order to calculate the threshold price for each month of the year. This monthly threshold price establishes when demand curtailments are deemed to be beneficial to the *IGO*'s system for each day of that month. The determination of the monthly threshold price consists in three steps:

(i) determination of a representative offer curve for the month,

(ii) smoothing of the representative offer curve, and

(iii) determination of the point where the smoothed representative offer curve becomes inelastic.

The construction of the representative offer curve for month m of year y requires the use of the offer data for the same month m in the year $y-1$. The *IGO* collects the offer data from each hour of that month. The hours pertaining to the month m form the set

$$H\big|_m = \left\{h : h = 1, 2, \ldots, H\big|_m\right\},\ m = 1, 2, \ldots, 12,\ \textit{for year } y-1.$$

For each hour $h \in H\big|_m$, the offers made by each of the $S\big|_{m,h}$ sellers who participated in the hourly *DAM* are used to construct the sets

$$E^s\big|_{m,h} = \left\{\left\{\tilde{p}^{s,\eta}\big|_{m,h}, \sigma^{s,\eta}\big|_{m,h}\right\}, \eta = 1, 2, \ldots, E^s\big|_{m,h}\right\},\ s = 1, 2, \ldots, S\big|_{m,h};\ h = 1, 2, \ldots, H\big|_m;\ m = 1, 2, \ldots, 12.$$

The offer is the order pair $\left\{\tilde{p}^{s,\eta}\big|_{m,h}, \sigma^{s,\eta}\big|_{m,h}\right\}$ with $\tilde{p}^{s,\eta}\big|_{m,h}$ representing the capacity offered by seller s at price $\sigma^{s,\eta}\big|_{m,h}$. Since at each hour a seller may offer power at various prices, we use the superscript η to denote each of the segments of the seller's s offer for hour h. We depict in Fig. 2.4 the aggregated offer supply curve of seller s at hour h.

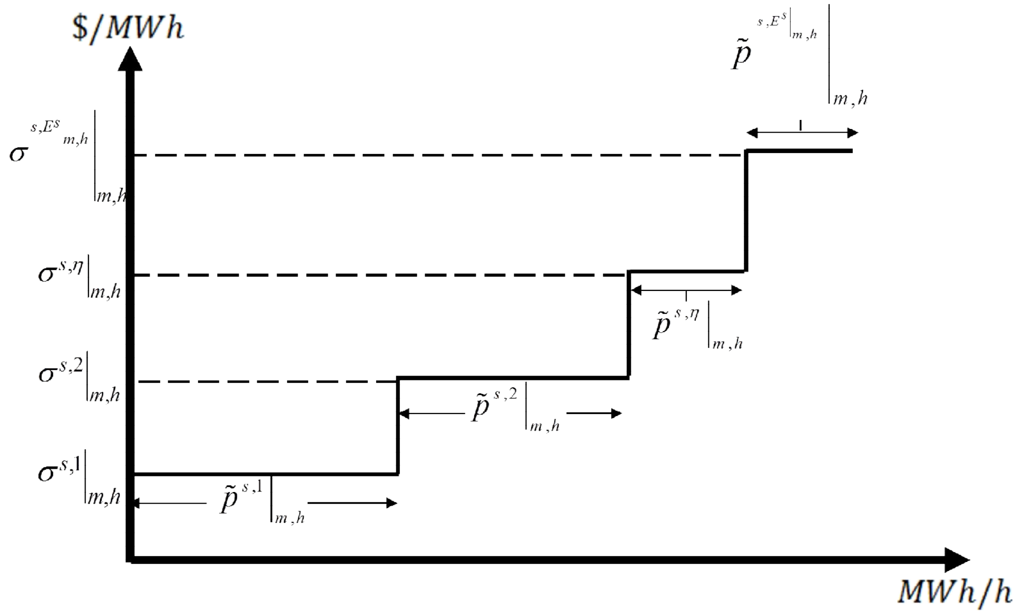

Figure 2.4: Seller *s*'s offer supply curve for hour *h* in month *m*

The construction of a representative offer curve entails the collection of all the sellers' offers for each hour h of month m of year $y-1$ and their sorting them into $K\big|_m+1$ "buckets". The "bucket" $G^{(k)}\big|_{m,h}$ is the sub-set that contains the indices (s,η) of the sellers whose prices fall in the interval $\left[\gamma^{(k-1)}\big|_m, \gamma^{(k)}\big|_m\right], k=1,2,\ldots,K\big|_m+1.$ These price levels may be set arbitrarily by the *IGO* and depend on the minimum and maximum offers permitted in the *IGO*'s market. The price levels satisfy

$$\gamma^{(k)}\Big|_m = \gamma^{(k-1)}\Big|_m + \Delta\gamma\Big|_m,\ k=1,2,\ldots,K\Big|_m;\ m=1,2,\ldots,12. \qquad (2.1)$$

$\Delta\gamma\big|_m$ is the step size between the price levels and is selected by the *IGO* based on the resolution desired for the offer curve construction. We denote by $\gamma^{(K|_m)}\big|_m$ the monthly ceiling offer price and by $\gamma^{(0)}\big|_m$ the monthly floor price. The bucket $\mathsf{G}^{(k)}\big|_{m,h}$ is defined formally by

$$\mathsf{G}^{(k)}\big|_{m,h} = \left\{(s,\eta):\gamma^{(k-1)}\big|_m < \sigma^{s,\eta}\big|_{m,h} \leq \gamma^{(k)}\big|_m\right\},\ 1 \leq s \leq S\big|_{m,h};\ 1 \leq \eta \leq E^s\big|_{m,h};$$
$$k = 1,2,\ldots,K\big|_m;\ h = 1,2,\ldots,H\big|_m;$$
$$m = 1,2,\ldots,12.$$

For $k = 0$, we define a separate floor-price bucket $\mathsf{G}^{(0)}\big|_{m,h}$ as

$$\mathsf{G}^{(0)}\big|_{m,h} = \left\{(s,1):\sigma^{s,1}\big|_{m,h} = \gamma^{(0)}\big|_m\right\},\ 1 \leq s \leq S\big|_{m,h};\ h = 1,2,\ldots,H\big|_m;\ m = 1,2,\ldots,12,$$

where $\eta = 1$ because only the lowest-priced offer of each seller s may be set to the floor price.

In order to provide a representative value of how much power was offered in the month m within the interval delimited by two adjacent price levels, $\gamma^{(k-1)}\big|_m$ and $\gamma^{(k)}\big|_m$, $k = 1,2,\ldots,K\big|_m$, we use all the indices (s,η) collected in the bucket $\mathsf{G}^{(k)}\big|_{m,h}$, $k = 0,1,2,\ldots,K\big|_m$, to evaluate $g^{(k)}\big|_m$, the average capacity offered:

$$g^{(k)}\Big|_m = \frac{\sum_{h\in H|_m}\sum_{(s,\eta)\in G^{(k)}|_{m,h}} \tilde{p}^{s,\eta}\Big|_{m,h}}{\sum_{h\in H|_m}\left|G^{(k)}\Big|_{m,h}\right|},\ k=0,1,2,\dots,K\big|_m;\ m=1,2,\dots,12. \quad (2.2)$$

Each $g^{(k)}\big|_m$ is paired with its corresponding price level $\gamma^{(k)}\big|_m$, for $k=0,1,2,\dots,K\big|_m$. In Fig. 2.5 we plot as a step function all the price levels $\gamma^{(k)}\big|_m$, for $k=0,1,2,\dots,K\big|_m$ with respect with the cumulative sum of all the $g^{(k)}\big|_m$, for $k=0,1,2,\dots,K\big|_m$. The curve constructed with the segments of length $g^{(k)}\big|_m$ at the corresponding price levels $\gamma^{(k)}\big|_m$ is called the representative offer curve (*ROC*).

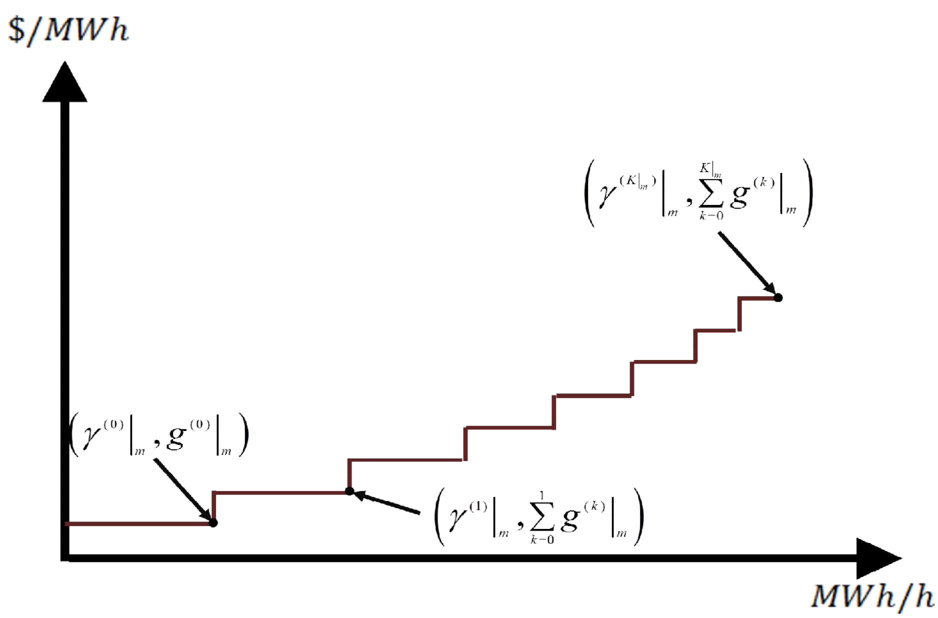

Figure 2.5: The representative offer curve for month *m*

The *ROC* is the vehicle used to determine the *NBT* threshold value. *FERC* mandated each *IGO* to use numerical methods to determine a smoothed and differentiable version of the *ROC* [7, pp. 63]. The *IGO*'s may use any numerical criterion to determine the expression for the continuous function $\rho(\cdot)|_m$ that "best" fits the data of each monthly *ROC*. We refer to $\rho(\cdot)|_m$, $m = 1, 2, \ldots, 12$ as the adjusted representative offer curve (*AROC*) for the month *m* (see Fig. 2.6). Typical expressions for $\rho(\cdot)|_m$ include polynomial, exponential and logarithmic functions. Each *IGO* has the freedom to choose which function they consider fits best the *ROC*.

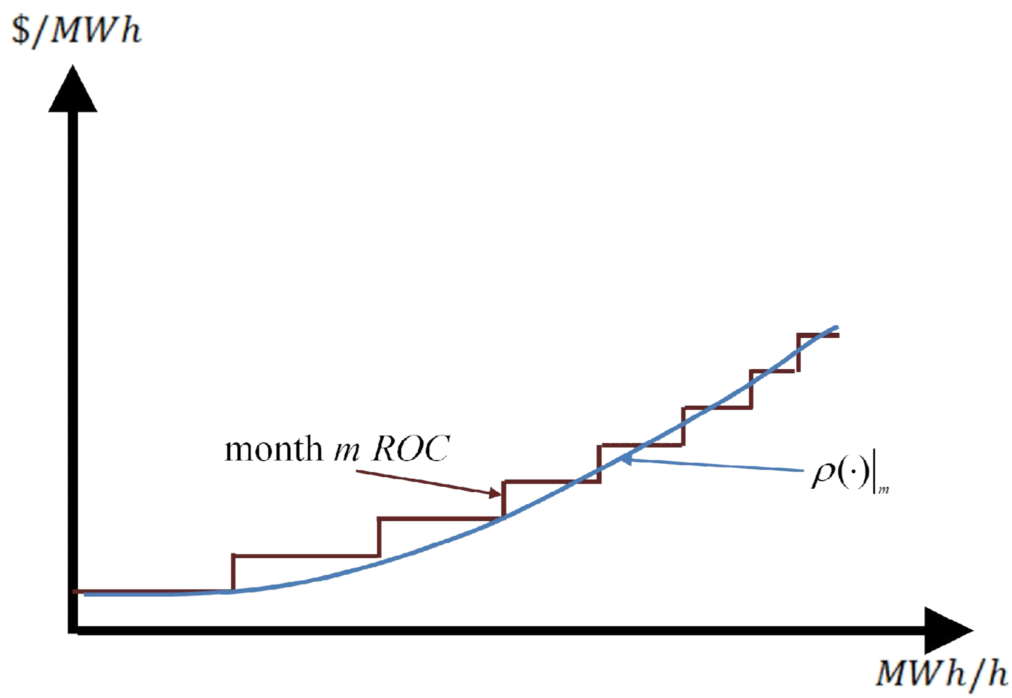

Figure 2.6: Adjusted representative offer curve for month *m*

The *FERC* mandated threshold price is determined using the *AROC* for each month. This threshold determines the price beyond which the benefit to the load from the reduced *LMP* resulting from the demand curtailments exceeds the total payments to the *DRR*s. Based on *FERC*'s analysis, the threshold point along the *AROC* is located where the *AROC* becomes inelastic. In other words, demand curtailments are cost-effective when the nature of the *AROC* is such that small decreases in generation being called to serve load will result in *LMP* decreases that are sufficient to offset the payments to the *DRR*s [7, pp. 63]. The *NBT* condition is giving using the *AROC* as:

$$\frac{d\,\rho(\ell)\big|_m}{d\ell} = \frac{\rho(\ell)\big|_m}{\ell},\ m = 1, 2, \ldots, 12. \tag{2.3}$$

Let $\ell^{\upsilon}\big|_m$ denote the solution of (2.3) and set $\upsilon\big|_m$ the monthly threshold price with

$$\upsilon\big|_m = \rho\left(\ell^{\upsilon}\big|_m\right)\Big|_m,\ m = 1, 2, \ldots, 12. \tag{2.4}$$

Each *IGO* must use these monthly threshold prices to determine the dispatch of the demand curtailments into the *DAM*s. Whenever the *LMP* at a node is greater or equal to $\upsilon\big|_m$ for each month, the *IGO* dispatches all the *DRR*s that offered demand curtailment at this node. Each such *DRR* is paid at the post-curtailment *LMP* outcome of the *DAM* for each MW curtailed in hour *h*.

2.3 Application of the *NBT* in the *DAM*s

In this section, we analyze the repercussions of the *FERC NBT* using the extended transmission constrained market model with the explicit representation of the *DRRs*. We use typical market performance metrics needed to assess the outcomes of the *DAM*s. We focus on the *DAM* operated by the *IGO* for the MWh commodity in the hour h and represent the system by a snapshot that is assumed to hold for the entire hour. To determine the offers and bids that are accepted and the associated amounts and prices for each seller and buyer, the *IGO* uses the solution of the market clearing *OPF*. We review briefly the formulation of this problem and state its extension with the explicit representation of the *DRR*s.

We consider a *DAM* that consists of a set of $S\big|_{m,h}$ sellers, denoted by $\mathsf{S}\big|_{m,h}$, and a set of $B\big|_{m,h}$ buyers, denoted by $\mathsf{B}\big|_{m,h}$. For $h \in \mathsf{H}\big|_{m}$, $m = 1, 2, \ldots, 12$, let us denote the integral of the seller s's marginal offer price by $\chi^{s}\left(p^{s}\right)\Big|_{m,h}$ as a function of the real power supply p^{s} and the integral of the buyer b's marginal bid price by $\beta^{b}(p^{b})\Big|_{m,h}$ as a function of the real power demanded p^{b}.

The objective of the *IGO* is to maximize the societal net benefits given by the difference between the benefits $\sum_{b=1}^{\mathsf{B}|_{m,h}} \beta^{b}(p^{b})\Big|_{m,h}$ of the buyers and the costs $\sum_{s=1}^{\mathsf{S}|_{m,h}} \chi^{s}\left(p^{s}\right)\Big|_{m,h}$ to purchase from the sellers. We next provide a statement of the constraints that are considered in the formulation: the power flow relations at each node and the real power flow capacity in the transmission lines. We consider a transmission network with the $(N+1)$ buses in the set $\mathcal{N}$, with

$$\mathcal{N} = \{ n : n = 0,1,\ldots,N \},$$

and the L lines in the set

$$\mathcal{J} = \{ j : j = 1,2,\ldots,J \}.$$

We assume that the DC power flow conditions hold. We denote the diagonal branch susceptance matrix by $\underline{\boldsymbol{B}}_d$ and the reduced branch-to-node incidence matrix by $\underline{\boldsymbol{A}}$. We denote the slack bus nodal susceptance vector by $\underline{\boldsymbol{b}}_0$ [22],[27].

We define $p_n'^g\big|_{m,h}$ $\left(p_n'^d\big|_{m,h}\right)$ as the total power generated (demanded) at node *n*. The expressions for these variables are

$$p_n'^g\Big|_{m,h} = \sum_{\substack{s \in \mathcal{S} \text{ is} \\ \text{at node } n}} p^s,\ n = 0,1,2,\ldots,N \tag{2.5}$$

and

$$p_n'^d\Big|_{m,h} = \sum_{\substack{b \in \mathcal{B} \text{ is} \\ \text{at node } n}} p^b,\ n = 0,1,2,\ldots,N. \tag{2.6}$$

We construct the injection power vector

$$\underline{\boldsymbol{p}}'^{g}\Big|_{m,h} \triangleq \left[p_1'^{g}\Big|_{m,h}, p_2'^{g}\Big|_{m,h}, \ldots, p_N'^{g}\Big|_{m,h} \right]^T \in \mathbb{R}^N$$

and in the withdrawal vector

$$\underline{\boldsymbol{p}}'^{d}\Big|_{m,h} \triangleq \left[p_1'^{d}\Big|_{m,h}, p_2'^{d}\Big|_{m,h}, \ldots, p_N'^{d}\Big|_{m,h} \right]^T \in \mathbb{R}^N,$$

respectively.

We write the power flow equations as

$$\underline{\boldsymbol{p}}'^{g}\Big|_{m,h} - \underline{\boldsymbol{p}}'^{d}\Big|_{m,h} = \underline{\boldsymbol{B}}\,\underline{\boldsymbol{\theta}}'\Big|_{m,h}, \tag{2.7}$$

and the power flow equation for the slack node as

$$p_0'^{g}\Big|_{m,h} - p_0'^{d}\Big|_{m,h} = \underline{\boldsymbol{b}}_0^T\,\underline{\boldsymbol{\theta}}'\Big|_{m,h}, \tag{2.8}$$

where $\underline{\boldsymbol{\theta}}'\big|_{m,h}$ is the vector containing the nodal voltage phase of all nodes. The real power flows at each line are calculated as

$$\underline{\boldsymbol{f}}'\Big|_{m,h} = \underline{\boldsymbol{B}}_d\,\underline{\boldsymbol{A}}\,\underline{\boldsymbol{\theta}}'\Big|_{m,h}. \tag{2.9}$$

We model the constraints on the real power flows of the lines of the system using the inequality

$$\underline{\boldsymbol{f}}'\Big|_{m,h} \leq \underline{\boldsymbol{f}}^{max}, \tag{2.10}$$

where $\underline{\boldsymbol{f}}^{max}$ is the vector containing all the real power flow limits at each line and we denote it as $\underline{\boldsymbol{f}}^{max} \triangleq \left[f_1^{max}, f_2^{max}, \ldots, f_J^{max} \right]^T$.

We can now state the formulation of the transmission constrained *DAM* problem (*TCDAMP*) as

$$\begin{cases} \max \displaystyle\sum_{b=1}^{\mathsf{B}|_{m,h}} \beta^b(p^b)\Big|_{m,h} - \sum_{s=1}^{\mathsf{S}|_{m,h}} \chi^s(p^s)\Big|_{m,h} \\ \textit{subject to} \\ \underline{\boldsymbol{p}}'^g\Big|_{m,h} - \underline{\boldsymbol{p}}'^d\Big|_{m,h} = \underline{\boldsymbol{B}}\,\underline{\boldsymbol{\theta}}'\Big|_{m,h} \quad \leftrightarrow \quad \underline{\boldsymbol{\lambda}}'\big|_{m,h} \\ p_0'^g\Big|_{m,h} - p_0'^d\Big|_{m,h} = \underline{\boldsymbol{b}}_0^T\,\underline{\boldsymbol{\theta}}'\Big|_{m,h} \quad \leftrightarrow \quad \lambda_0'\big|_{m,h} \\ \quad \underline{\boldsymbol{B}}_d\,\underline{\boldsymbol{A}}\,\underline{\boldsymbol{\theta}}'\Big|_{m,h} \le \underline{\boldsymbol{f}}^{max} \quad \leftrightarrow \quad \underline{\boldsymbol{\mu}}'\big|_{m,h} \end{cases} \tag{2.11}$$

We denote (2.11) as $M\left(\mathsf{S}|_{m,h}, \mathsf{B}|_{m,h}\right)$ and since no *DRR*s are included as market participants we call it the pre-curtailment *DAM* [21]. The solution of $M\left(\mathsf{S}|_{m,h}, \mathsf{B}|_{m,h}\right)$ determines the optimum values of the dual variables associated with the power balance constraints and the line flow constraints. We call $\left[\lambda_n'|_{m,h}\right]^*$ the pre-curtailment *LMP* at node $n \in N$,and $\left[p_n'^g|_{m,h}\right]^*$ and $\left[p_n'^d|_{m,h}\right]^*$ are the cleared generation and demand, respectively, at that node .

The pre-curtailment purchase payments at node *n* are given by

$$w_n'^B\Big|_{m,h} = \left[\lambda_n'\big|_{m,h}\right]^* \cdot \left[p_n'^d\big|_{m,h}\right]^*, \tag{2.12}$$

and their sum constitutes the system pre-curtailment purchase payments

$$w'^B\Big|_{m,h} = \sum_{n=0}^{N}\left[\lambda_n'\big|_{m,h}\right]^* \cdot \left[p_n'^d\big|_{m,h}\right]^*. \tag{2.13}$$

Similarly, the pre-curtailment total producer revenues are

$$w'^S\Big|_{m,h} = \sum_{n=0}^{N}\left[\lambda_n'\big|_{m,h}\right]^* \cdot \left[p_n'^g\big|_{m,h}\right]^*. \tag{2.14}$$

In addition, we evaluate the pre-curtailment congestion rents $\kappa'\big|_{m,h}$

$$\kappa'\big|_{m,h} = \sum_{n=0}^{N}\left[\lambda_n'\big|_{m,h}\right]^* \cdot \left[p_n'^d\big|_{m,h}\right]^* - \sum_{n=0}^{N}\left[\lambda_n'\big|_{m,h}\right]^* \cdot \left[p_n'^g\big|_{m,h}\right]^*. \tag{2.15}$$

The *IGO* uses the outcomes of $M\left(S\big|_{m,h}, B\big|_{m,h}\right)$ to assess the participation of the *DRR*s in the *DAM* of hour *h* in line with *FERC NBT* cost-effectiveness criterion. The *IGO* collects the set of nodes whose pre-curtailment *LMP*s are at or above the threshold price $\upsilon\big|_m$ to construct

$$\hat{N}\Big|_{m,h} = \left\{n : \left[\lambda_n'\big|_{m,h}\right]^* \geq \upsilon\big|_m\right\}.$$

Each *DRR* at a node $n \in \hat{N}\Big|_{m,h}$ is dispatched by the *IGO*. We denote the set of buyers with demand-response capability by $\hat{B}\Big|_{m,h}$. We denote $\bar{B}\Big|_{m,h}$ as the set that contains all the pure buyers in the electricity market. The total demand-curtailment at each node $n \in N$ is

$$\hat{p}_n^d\Big|_{m,h} = \begin{cases} \sum\limits_{\substack{\hat{b}=1 \\ \hat{b}\, at\, n}}^{\hat{B}|_{m,h}} \hat{p}^{\hat{b}}, & n \in \hat{N}\Big|_{m,h} \\ 0, & n \notin \hat{N}\Big|_{m,h} \end{cases}. \tag{2.16}$$

We impose the condition that a *DRR* player cannot offer a demand curtailment that exceeds his demand. We construct the nodal demand curtailment vector

$$\underline{\hat{\boldsymbol{p}}}^d\Big|_{m,h} \triangleq \left[\hat{p}_1^d\Big|_{m,h}, \hat{p}_2^d\Big|_{m,h}, \ldots, \hat{p}_N^d\Big|_{m,h} \right]^T \in \mathbb{R}^N.$$

In order to take into account the *DRR*s that cleared the *NBT* threshold, we modify the objective function and the power flow constraints of $M\left(S\big|_{m,h}, B\big|_{m,h}\right)$ to include the nodal demand curtailments. We formulate the *DAM* with the demand response participation $M\left(S\big|_{m,h}, \bar{B}\big|_{m,h}, \hat{B}\big|_{m,h}\right)$ as:

$$
\begin{cases}
\max \sum_{\bar{b} \in \bar{\mathsf{B}}|_{m,h}} \beta^{\bar{b}}(p^{\bar{b}})\Big|_{m,h} + \sum_{\hat{b} \in \hat{\mathsf{B}}|_{m,h}} \beta^{\hat{b}}(p^{\hat{b}})\Big|_{m,h} - \\
\qquad\qquad \sum_{s \in \mathsf{S}|_{m,h}} \chi^{s}(p^{s})\Big|_{m,h} - \sum_{\hat{b} \in \hat{\mathsf{B}}|_{m,h}} \chi^{\hat{b}}(p^{\hat{b}})\Big|_{m,h} \\
\textit{subject to} \\
\underline{\boldsymbol{p}}^{g}\Big|_{m,h} - \left(\underline{\boldsymbol{p}}^{d}\Big|_{m,h} - \underline{\hat{\boldsymbol{p}}}^{d}\Big|_{m,h}\right) = \underline{\boldsymbol{B}}\,\underline{\boldsymbol{\theta}}\Big|_{m,h} \quad \leftrightarrow \quad \underline{\boldsymbol{\lambda}}\Big|_{m,h} \\
p_0^{g}\Big|_{m,h} - \left(p_0^{d}\Big|_{m,h} - \hat{p}_0^{d}\Big|_{m,h}\right) = \underline{\boldsymbol{b}}_0^{T}\,\underline{\boldsymbol{\theta}}\Big|_{m,h} \quad \leftrightarrow \quad \lambda_0\Big|_{m,h} \\
\underline{\boldsymbol{B}}_d\,\underline{\boldsymbol{A}}\,\underline{\boldsymbol{\theta}}\Big|_{m,h} \le \underline{\boldsymbol{f}}^{\max} \quad \leftrightarrow \quad \underline{\boldsymbol{\mu}}\Big|_{m,h}
\end{cases}
\tag{2.17}
$$

Equation (2.17) is referred to as the *DAM* with *DRR* participation and its solution as the post-curtailment outcomes, which are used to settle the *DAM* [22]-[27]. We call $\left[\lambda_n\big|_{m,h}\right]^*$ the post-curtailment *LMP* at node $n \in N$, and $\left[p_n^g\big|_{m,h}\right]^*$ $\left(\left[p_n^d\big|_{m,h}\right]^*\right)$ the cleared post-curtailment generation (demand). The total purchase payments to the *DRR*s in hour *h* are

$$
\zeta\big|_{m,h} = \sum_{n \in \hat{N}} \left[\lambda_n\big|_{m,h}\right]^* \cdot \left[\hat{p}_n^d\big|_{m,h}\right]^* . \tag{2.18}
$$

The total hourly benefits are

$$
u^N\Big|_{m,h} = \sum_{n \in N^+|_{m,h}} \left(\left[\lambda_n'\big|_{m,h}\right]^* - \left[\lambda_n\big|_{m,h}\right]^*\right) \cdot \left(\left[p_n^d\big|_{m,h}\right]^* - \left[\hat{p}_n^d\big|_{m,h}\right]^*\right), \tag{2.19}
$$

where $N^+\big|_{m,h} \subset N$ is the subset of nodes that benefit from the demand curtailments defined by

$$N^+\big|_{m,h} = \left\{ n : \left[\lambda_n\big|_{m,h} \right]^* < \left[\lambda'_n\big|_{m,h} \right]^* \right\}.$$

The additional hourly per-unit charge, $v\big|_{m,h}$, for the buyers due to the payment to the *DRR*s is given by

$$v\big|_{m,h} = \frac{\sum_{n \in \hat{N}} \left[\lambda_n\big|_{m,h} \right]^* \cdot \left[\hat{p}_n^d\big|_{m,h} \right]^*}{\sum_{n \in N^+} \left(\left[p_n^d\big|_{m,h} \right]^* - \left[\hat{p}_n^d\big|_{m,h} \right]^* \right)}. \tag{2.20}$$

In essence, a buyer at node $n \in N^+$ pays $\left(\left[\lambda_n\big|_{m,h} \right]^* + v\big|_{m,h} \right)$ \$/MWh for its consumption in hour *h*. The total post-curtailment consumer payments at node *n*, $w_n^B\big|_{m,h}$, are

$$w_n^B\big|_{m,h} = \left(\left[\lambda_n\big|_{m,h} \right]^* + v\big|_{m,h} \right) \cdot \left(\left[p_n^d\big|_{m,h} \right]^* - \left[\hat{p}_n^d\big|_{m,h} \right]^* \right). \tag{2.21}$$

The total post-curtailment purchase payments are

$$w^B\big|_{m,h} = \sum_{n \in N} \left(\left[\lambda_n\big|_{m,h} \right]^* + v\big|_{m,h} \right) \cdot \left(\left[p_n^d\big|_{m,h} \right]^* - \left[\hat{p}_n^d\big|_{m,h} \right]^* \right). \tag{2.22}$$

The post-curtailment producer revenues are

$$w^S\Big|_{m,h} = \sum_{n \in N} \left[\lambda_n\Big|_{m,h} \right]^* \cdot \left[p_n^g\Big|_{m,h} \right]^*. \tag{2.23}$$

The post-curtailment congestion rents are

$$\begin{aligned} \kappa\Big|_{m,h} = \sum_{n \in N} \left(\left[\lambda_n\Big|_{m,h} \right]^* + \nu\Big|_{m,h} \right) \cdot \left(\left[p_n^d\Big|_{m,h} \right]^* - \left[\hat{p}_n^d\Big|_{m,h} \right]^* \right) - \\ \sum_{n \in N} \left[\lambda_n\Big|_{m,h} \right]^* \left[p_n^g\Big|_{m,h} \right]^* - \zeta\Big|_{m,h}. \end{aligned} \tag{2.24}$$

The pre-curtailment metrics in (2.18) – (2.24) are used to assess the impacts of the demand curtailments in the electricity markets. The benefits of demand curtailments may be evaluated by a comparative analysis of pre- and post-curtailment market outcomes. In essence, the *IGO* runs the *DAM* without considering the demand-curtailment offers, then determines the *DRR*s that satisfy the *NBT* and then runs the *DAM* again, this time considering the demand-curtailment offers.

2.4 Summary

In this chapter, we reviewed the thrust of the *FERC* Order No. 745 and provided an analytic framework for the evaluation of the impacts. We discussed the requirements of the *NBT* as mandated by the *FERC* and provided an economic analysis. We discussed in detail the procedure required to determine the monthly threshold price. We also analyzed the repercussions of the *FERC NBT* using the extended transmission constrained market model with the explicit representation of the *DRRs*.

CHAPTER 3

IMPACTS OF THE *NBT* IN THE *DAM*s

We devote this chapter to present representative results of extensive simulation studies to assess the impacts of demand curtailments in the DAMs under Order No. 745 rules. We discuss the system-wide effects of the demand curtailments and identify the key unintended consequences associated with the dispatch of DRRs. We identify two important ramifications of the FERC NBT: the increase in payments incurred by loads due to the dispatch of DRRs and the increases in the post-curtailment LMPs at some nodes of the system. In Section 3.1, we start by a description of the test system used and discuss the nature and scope of the studies. Section 3.2, we analyze the outcomes of the DRR dispatch under the NBT requirements. In Section 3.3, we discuss the issues associated with the increase in the post-curtailment LMPs at certain nodes in the system and discuss their impacts.

3.1 Scope and Nature of the Simulations

We use the results of representative simulation studies to identify some important impacts of the *NBT* which were not intended by the *FERC* Order No. 745. In this section we summarize the key characteristics of the representative case studies used to assess the impacts of the *NBT* in the outcomes of the *DAM*s. For all the studies presented, we use a test system based on the modified *IEEE* 118-bus system [28]. A detailed description of the test system can be found in Appendix A.

We use the load shapes from the year 2010 of ISO New England (*ISO-NE*) and the Midwest *ISO* (*MISO*). The system load demand at a given hour is the aggregated hourly demand of all the loads in the system. The load at each node in the test system is a specified fraction of the system load demand. We scale the loads so that the annual peak load equals 9,600 MW. We use the monthly *ROC*s of the two *ISO*s to construct the test system offer curves. For each month, we make the test system offer curve to have the same shape as the corresponding monthly *ROC*.

Each load node in the system is able to provide demand curtailments. The total capacity of demand response at each node in the system is expressed as a fraction of the annual peak load demand at the node. In the studies, we investigate the impacts of various levels of demand response capacity percentages c and evaluate the impacts of demand curtailments on the system. In these studies, we limit the *DRR* dispatch to the afternoon hours from 2 P.M to 7 P.M to emulate realistic conditions in the DAMs of the ISOs. In table 3.1 we summarize the characteristics of the case studies.

Table 3.1: Description of the case studies

case	description
case N_c	*ISO-NE* offer and load shapes with demand response capacity percentage *c*
case M_c	*MISO* offer and load shapes with demand response capacity percentage *c*

We refer to N_0 and M_0 as the base cases for the two sensitivity studies without demand response dispatch. We use each base case as reference with respect to which we measure the impacts of demand curtailments in the sensitivity studies.

3.2 System-Wide Impacts of Demand Curtailments

The system-wide benefits arising from demand curtailments have been documented earlier [18], [19], [22]. The principal benefits include a reduction in the annual peak load demand, lower purchase payments by the non-curtailed loads and a drop in the congestion rents collected by the *ISO*. In this section, we describe the system-wide benefits we encountered in our simulation studies due to demand curtailments. We start with the base cases N_0 and M_0 with no demand response capacity available. In Table 3.2, we show the hourly and annual values of the cleared demand, buyer payments and congestion rents for case N_0 . Next, we present the results of the simulation with 3% demand response capacity in Table 3.3.

Table 3.2: Case N_0 system-wide metrics

metric	hourly values			annual values
	average	max	min	
cleared demand (MWh)	5,443	9,600	3,363	47.68×10^6
buyer payments (million $)	0.378	3.824	0.081	3,316
congestion rents (million $)	0.033	0.181	0	294.99

Table 3.3: Case N_3 system-wide metrics

metric	hourly values			annual values
	average	max	min	
cleared demand (MWh)	5,401	9,449	3,363	47.31×10^6
buyer payments (million $)	0.369	3.202	0.081	3,237
congestion rents (million $)	0.024	0.181	0	216.05

We can infer from the preceding tables that the 3% demand response curtailments result in noticeable system-wide benefits. The total cleared demand reduction was 0.37×10^6 MWh, which represents a 0.77% reduction when compared to the case with no demand response participation. The reduction in cleared demand resulted in a reduction in the system-wide buyer payments of $79 million. An interesting by-product is the 27% reduction in the total congestion rents. We tabulate the system-wide metrics for the cases M_0 and M_3 in the Tables 3.4 and 3.5, respectively.

Table 3.4: Base case M_0 system-wide metrics

metric	hourly values			annual values
	average	max	min	
cleared demand (MWh)	6,056	9,683	3,953	53.05×10^6
buyer payments (million $)	0.352	1.791	0.144	3,090
congestion rents (million $)	0.013	0.051	0	115.63

Table 3.5: Case M_3 system-wide metrics

metric	hourly values			annual values
	average	max	min	
cleared demand (MWh)	6,020	9,393	3,953	52.73×10^6
buyer payments (million $)	0.349	0.884	0.144	3,060
congestion rents (million $)	0.009	0.051	0	85.90

The results from M_3 show that the 3% demand response capacity also results in system-wide benefits. A reduction of 0.6% in cleared demand results in $30 million of savings to the consumers. The congestion rents in M_3 are 25% lower than the congestion rents in case M_0.

The results for these two test cases provide a representative illustration of the beneficial impacts of demand curtailments in the *DAM*s. However, there are also unintended consequences that may result from the dispatch of *DRR*s under the rules of *FERC* Order No. 745. We next examine the negative impacts that result from demand curtailments.

Due to the nature of the *FERC NBT* rules, specifically, the use of a system-wide threshold price to judge when nodal demand curtailments are beneficial to all market participants, there are instances where the societal costs of *DRR* participation are higher than its benefits. We say an instance where the societal costs of demand response are higher than the benefits has occurred when the payments to the *DRR*s outweigh the savings resulting from a lower post-curtailment *LMP*. This issue is called the unit billing effect in Order No. 745 and *FERC* accepts this result due to the "apparent computational difficulty of adopting a dynamic approach that incorporates the billing unit effect in the dispatch algorithms at this time" [7, pp. 64]. In this section, we show how often these instances occurred in our simulation studies.In Table 3.6, we show, in a monthly basis, the metrics associated with the inefficient demand curtailments in case N_3. We present the monthly percentage of curtailments that resulted in extra buyer payments. This is calculated by dividing the number of hours that resulted in extra payments due to demand response by the total hours during which curtailments were allowed.

Table 3.6: Extra payments due to demand response curtailments in case N_3

month of 2010	percentage of hours with extra payments	extra payments due to demand curtailments ($)			
		hourly values			monthly values
		average	max	min	
Jan	71	4,581	11,463	1,467	293,214
Feb	62	9,470	18,069	3,795	482,954
Mar	5	4,401	5,820	923	30,804
Apr	11	4,033	4,725	4,640	56,457
May	10	5,017	17,255	2,915	65,218
Jun	5	6,075	20,289	3,674	42,523
Jul	10	13,370	23,851	2,274	187,184
Aug	19	10,076	23,982	665	261,984
Sep	3	7,292	29,341	116	36,461
Oct	5	5,897	6,245	5,440	41,280
Nov	31	5,797	10,518	3,774	237,676
Dec	18	2,101	4,820	921	54,617

Also shown are the hourly and monthly values of the extra payments due to the inefficient dispatch of *DRR*s. These extra payments are computed by calculating the difference between the demand response benefits and the payments to the *DRR*s. We see that during the months of January and February, approximately 71 and 62 percent of the hours during which demand curtailments were allowed, resulted in an inefficient dispatch of *DRR*s. This means that, for these two months, the *NBT* incorrectly deemed cost-effective several hours that in the end resulted in higher consumer payments. In other words, the *NBT* was wrong for more than half of the curtailment hours.

In Table 3.7, we show demand response curtailment metrics for case M_3. For the months of October and November, we see that all of the demand curtailments that the *NBT* deemed cost-effective resulted in higher buyer payments. Contrary to what is intended from the dispatch of *DRR*s, they resulted in an increase of the total monthly buyer payments due to the demand curtailments. Furthermore, only the months of June, July and August have a larger number of efficient curtailments.

Table 3.7: Extra payments due to demand response curtailments in case M_3

month of 2010	percentage of hours with extra payments	extra payments due to demand curtailments ($)			
		hourly values			monthly values
		average	max	min	
Jan	69	2,750	21,064	6	233,770
Feb	89	2,679	7,737	521	286,692
Mar	81	2,668	6,907	8	277,449
Apr	96	6,453	11,009	440	819,479
May	75	3,608	14,429	448	238,129
Jun	40	2,325	8,721	204	125,524
Jul	10	4,015	11,350	461	56,205
Aug	21	5,182	10,312	139	145,086
Sep	50	3,083	7,592	490	107,915
Oct	100	4,052	7,281	1,182	510,547
Nov	100	4,907	7,231	38	559,439
Dec	61	3,602	12,264	128	273,747

These extra payments are a result of the very small difference between the pre- and post-curtailment *LMP* at some nodes. A high post-curtailment *LMP* results in payments to the *DRR* such that they are not compensated by the benefits. We see that in some instances the *FERC NBT* fails to capture this situation in most curtailment hours. Also, we see that there exists a situation in which some nodes experience higher post-curtailment *LMP*s.

3.3 Nodes Negatively Impacted By Demand Curtailments

When demand curtailments are made, the post-curtailment power demands at the *DRR* nodes are modified with respect to the pre-curtailment state. This modification results in different outcomes in the congestion patterns in the system. The congestion rents may decrease at the nodes where demand curtailments are made, thus reducing the post-curtailment *LMP*s; however, this may not be the case in nodes that have little or no demand response participation.

Due to the system-wide nature of the *NBT*, the threshold price may not be a representative metric to correctly judge the cost-effectiveness of a demand curtailment at all nodes. In Fig. 3.1, we show the pre- and post-curtailment *LMP*s at node 8 for the week May 1 – 7, 2010, for the case N_3. Under the *NBT*, a *DRR* at node 8 is, therefore, deemed to be non-economic and so receives no compensation during the entire week. We see that during hours with demand curtailments at other nodes, the post-curtailment *LMP* at node 8 was actually higher than it was before with no demand response participation. Thus, the buyers at node 8 do not benefit from demand response and, in fact, are caused to incur higher prices by the curtailments made at other nodes. Such a situation is an unintended consequence of the *DRR* dispatch and negatively impacts the non-*DRR* buyers, who buy electricity at nodes that experience increases in the post-curtailment *LMP*s.

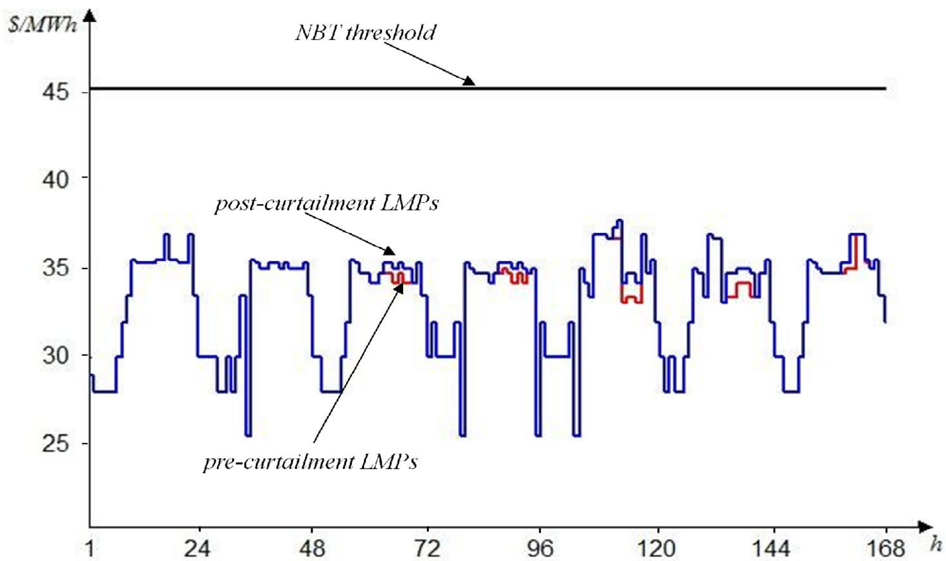

Figure 3.1: Pre- and post-curtailment *LMP*s during the week of May 1-7 at node 8 in study case N_3

Another interesting situation arises for the same May week at node 116. In Fig. 3.2, we plot the node 116 pre- and post-curtailment *LMP*s at node 116 for the same week as in the preceding figure. This node experiences reductions in the post-curtailment *LMP*s at all hours at which demand curtailments were allowed. Contrary to the situation with node 8, for node 116 the level of the monthly threshold price is such that, it permitted the dispatch of *DRR*s at several hours during the first week of May.

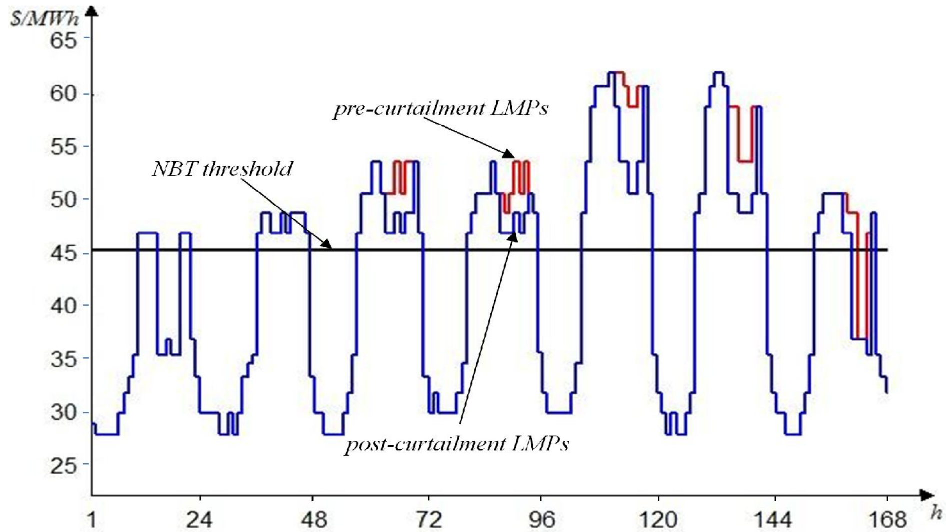

Figure 3.2: Pre- and post-curtailment *LMP*s during the week of May 1 -7 at node 116 in study case N_3

The discussion of the nodes 8 and 116 is indicative of the disparity in the way the nodes in the system are impacted by the demand curtailments. Indeed, our analysis of the N_3 and M_3 case studies indicates that there are nodes in the system experience higher post-curtailment *LMP* so often that at the end of the year their consumer payments were higher than the case without no-*DRR* participation. Out of the 99 load nodes, 19 experienced an increase in the annual consumer payments due to the demand curtailments for case N_3. In Table 3.8, we show consumer-payment related metrics for the 10 nodes that experienced the greatest percentage increase in load payments at the end of the year for case N_3. The node that experienced the highest percentage increase in the consumer payments with respect to case N_0, is node 8 at 1.17%.

Table 3.8: Nodes with increase in buyer payments in case study N_3

node number	percentage of nodal reduction of energy	nodal consumer payments	
		increase	% increase
1	0.316	190,872	0.76
2	0.316	70,815	0.71
3	0.316	149,245	0.78
4	0.290	169,688	0.90
6	0.312	202,248	0.79
8	0.248	153,291	1.17
11	0.316	249,220	0.72
12	0.318	160,341	0.69
13	0.345	81,697	0.47
16	0.323	75,630	0.60

For contrast, we show in Table 3.9 the nodes that experienced the highest decrease in consumer payments for case N_3. These nodes have greater demand response participation and also experience a decrease in the annual consumer payments of approximately 3% compared to case N_0. We also simulated cases with greater demand response penetration to study the impact on the negatively affected nodes. In Table 3.10, we show the percentage increase in consumer payments for different demand response capacities using *ISO-NE* data. We see that at the selected nodes the negative impacts get aggravated with the deeper penetration of demand response. We also see this situation with *MISO* data. Using *MISO* data, there are a total of 29 nodes that experience higher annual consumer payments with demand response participation.

Table 3.9: Nodes with the highest decrease in buyer payments in case study N_3

node number	percentage of nodal reduction of energy	nodal consumer payments	
		decrease	percentage decrease
42	0.895	2,464,001	2.94
49	0.895	2,216,223	2.92
54	0.895	2,897,158	2.94
56	0.895	2,154,083	2.94
59	0.895	7,141,640	2.94
60	0.895	2,015,031	2.95
62	0.895	1,988,482	2.95
80	0.889	3,149,489	2.84
90	0.889	3,929,569	2.83
116	0.895	4,633,195	2.90

Table 3.10: Percent increase in buyer payments for various *DRR* capacities with respect to case N_0

node number	percentage increase in consumer payments				
	case N_3	case N_5	case N_7	case N_9	case N_{11}
1	0.76	1.40	1.91	2.29	2.59
2	0.71	1.32	1.81	2.17	2.45
3	0.78	1.43	1.95	2.34	2.65
4	0.90	1.63	2.23	2.69	3.07
6	0.79	1.38	1.89	2.39	2.70
8	1.17	2.09	2.85	3.47	4.00
11	0.72	1.33	1.82	2.18	2.46
12	0.69	1.28	1.74	2.09	2.35
13	0.47	0.92	1.26	1.48	1.63
16	0.60	1.14	1.56	1.87	2.09

In Table 3.11, we show the percentage increase in consumer payments at the 10 nodes that experience the greatest negative impacts. We see that the percentage increase in consumer payments increases while there is more demand response capacity in the system.

Table 3.11: Percent increase in buyer payments for various *DRR* capacities with respect to case M_0

node number	percentage increase in consumer payments				
	case M_3	case M_5	case M_7	case M_9	case M_{11}
1	0.68	1.27	1.84	2.39	2.90
2	0.67	1.25	1.81	2.35	2.85
3	0.68	1.28	1.86	2.40	2.91
4	0.71	1.32	1.92	2.48	3.01
6	0.69	1.28	1.86	2.41	2.93
7	0.67	1.26	1.84	2.38	2.89
8	0.78	1.44	2.07	2.68	3.24
11	0.66	1.25	1.82	2.35	2.86
12	0.66	1.23	1.79	2.33	2.83
117	0.66	1.23	1.79	2.33	2.83

3.4 Summary

In this chapter, we summarized the impacts of demand curtailments in the *DAM*s using the results of our simulation studies. We briefly discussed the system-wide benefits such as the reduction in the system consumer payments and the system congestion rents. Most importantly, we identified the two key issues that arise when *DRR*s are allowed to participate in the *DAM* under Order No. 745 rules: the inefficient dispatch of *DRR*s and the negative impacts on some nodes in the system due to the increase in the post-curtailment *LMP*s.

CHAPTER 4

THE PROPOSED MODIFIED *NBT*

The determination of the monthly threshold price at which *DRR*s are allowed to participate in the *DAM*s and be compensated for curtailment services is determined without the explicit incorporation of the transmission congestion in the power system. This may result in some cases of buyers who do not participate in curtailments of their load paying higher post-curtailment prices than under pre-curtailment conditions and the undesirable outcomes as discussed in Chapter 3. In this chapter, we propose modifications to the *NBT* that take explicitly into account congestion and the nodal character of the *LMP*s in the determination of the monthly threshold price. We propose the modifications on the basis of the identified set of causal factors that we determined in Chapter 3. In Section 4.1, we provide an overview of the proposed modifications. We describe the proposed modified *NBT* to determine the nodal monthly threshold prices for a system and the introduction of a guarantee that ensures that no node fares worse under demand curtailments than without them. In Section 4.2, we present the results of representative simulation studies using the proposed modified *NBT* and show that they overcome the issues identified in Chapter 4. In Section 4.3, we provide a comparative analysis of the *NBT* and the proposed modified *NBT*.

4.1 Overview of the Proposed Modified *NBT*

We provide a concise mathematical statement of the modified NBT making use of some definitions we introduce. We define the set of indices of the weekdays of month *m* as

$$D\big|_m = \left\{ d : d = d_1, d_2, \ldots, D\big|_m \right\},\ m = 1, 2, \ldots, 12,\ \textit{for the year } y-1.$$

Here, $d_1 = 1$ if the first day is a week day, $d_1 = 2$ if the first day of the week is a Sunday and $d_1 = 3$ if the first day of the week is a Saturday. We collect the indices of the on-peak hours during the weekdays of month *m* in the set $D\big|_m$ to construct

$$\bar{H}\big|_m = \left\{ h : h = 7d, 8d, \ldots, 23d\, ; d = d_1, d_2, \ldots, D\big|_m \right\},\ m = 1, 2, \ldots, 12.$$

For each month of year and node of the system, we collect the *LMP*s that occurred during the on-peak hours of weekdays of the year $y-1$ in the set

$$\bar{E}_n\big|_m = \left\{ \left[\lambda_n\big|_{m,h} \right]^* : h \in \bar{H}\big|_m \right\},\ m = 1, 2, \ldots, 12;\ n = 0, 1, 2, \ldots, N.$$

We define the set containing the nodal price level indices as

$$\bar{K}_n\big|_m = \left\{ \bar{k} : \bar{k} = 0, 1, 2, \ldots, \bar{K}_n\big|_m \right\},\ m = 1, 2, \ldots, 12;\ n = 0, 1, 2, \ldots, N.$$

We collect the *LMP*s and sort them into $\bar{K}_n\big|_m + 1$ buckets. We define the ceiling price for each month and node as

$$\bar{\gamma}_n^{\left(\bar{K}_n|_m\right)}\Big|_m = \max_{\left[\lambda_n|_{m,h}\right]^* \in E_n|_m} \left(\left[\lambda_n\big|_{m,h}\right]^*\right), \; m = 1,2,\ldots,12;\; n = 0,1,2,\ldots,N, \quad (4.1)$$

and the floor price for each month and node as

$$\bar{\gamma}_n^{(0)}\Big|_m = \min_{\left[\lambda_n|_{m,h}\right]^* \in E_n|_m} \left(\left[\lambda_n\big|_{m,h}\right]^*\right), \; m = 1,2,\ldots,12;\; n = 0,1,2,\ldots,N. \quad (4.2)$$

$\bar{\gamma}_n^{\left(\bar{K}_n|_m\right)}\Big|_m$ and $\bar{\gamma}_n^{(0)}\Big|_m$ are the maximum and minimum price level for the month *m* and node *n*, respectively. The rest of the price levels are calculated using the recursion formula

$$\begin{aligned}\bar{\gamma}_n^{(\bar{k})}\Big|_m = \bar{\gamma}_n^{(\bar{k}-1)}\Big|_m + \Delta\bar{\gamma}_n\big|_m,\; \bar{k} = 1,2,\ldots,\bar{K}_n\big|_m - 1;\; m = 1,2,\ldots,12;\\ n = 0,1,2,\ldots,N,\end{aligned} \quad (4.3)$$

where $\Delta\bar{\gamma}_n\big|_m$ may be selected arbitrarily based on the level of resolution desired.

Now, we collect the indices of the hours during which the *LMP* at each node was between two price levels $\left(\bar{\gamma}_n^{(\bar{k}-1)}\Big|_m, \bar{\gamma}_n^{(\bar{k})}\Big|_m\right]$ in the bucket

$$\begin{aligned}\bar{G}_n^{(\bar{k})}\Big|_m = \left\{h : \bar{\gamma}_n^{(\bar{k}-1)}\Big|_m < \left[\lambda_n\big|_{m,h}\right]^* \le \bar{\gamma}_n^{(\bar{k})}\Big|_m\right\},\; h \in \bar{H}\big|_m;\; \bar{k} = 1,2,\ldots,\bar{K}_n\big|_m;\\ m = 1,2,\ldots,12;\; n = 0,1,2,\ldots,N.\end{aligned}$$

We define a separate set for the floor price level $\left.\overline{\gamma}_n^{(0)}\right|_m$ bucket

$$\left.\overline{G}_n^{(0)}\right|_m = \left\{ h : \left[\left.\lambda_n\right|_{m,h} \right]^* = \left.\overline{\gamma}_n^{(0)}\right|_m \right\},\ h \in \left.\overline{H}\right|_m,\ m = 1, 2, \ldots 12;\ n = 0, 1, 2, \ldots, N.$$

In order to obtain a representative figure of how much power was cleared within the interval between two adjacent price levels, we use the indices collected in the buckets to calculate the average power cleared in

$$\left.\overline{g}_n^{(\overline{k})}\right|_m = \frac{\sum_{h \in \left.\overline{G}_n^{(\overline{k})}\right|_m} \left[\left.p_n^d\right|_{m,h} \right]^*}{\left| \left.\overline{G}_n^{(\overline{k})}\right|_m \right|},\ \overline{k} = 0, 1, 2, \ldots, \left.K_n\right|_m;\ m = 1, 2, \ldots, 12; \quad n = 0, 1, 2, \ldots, N. \tag{4.4}$$

We assign to each $\left.\overline{g}_n^{(\overline{k})}\right|_m$ its corresponding price level $\left.\overline{\gamma}_n^{(\overline{k})}\right|_m$, for $\overline{k} = 0, 1, 2, \ldots, \left.K_n\right|_m$. Analogously to the way we used the *ROC* in Chapter 2, we plot as a step function all the price levels $\left.\overline{\gamma}_n^{(\overline{k})}\right|_m$ with respect to the cumulative sum of all the $\left.\overline{g}_n^{(\overline{k})}\right|_m$ for $\overline{k} = 0, 1, 2, \ldots, \left.K_n\right|_m$. We call the resulting curve the representative locational marginal price curve (*RLMPC*). Since each node of the system has different variations between the minimum and maximum *LMP*, we may use different resolutions to construct each nodal *LMP* curve

In order to determine the nodal threshold at each node for each month *m*, we smooth the representative *RLMPC* curve using numerical methods. We denote the smoothed *RLMPC* by as $\bar{\rho}_n(\cdot)\big|_m$. In line with the *FERC* mandate, we determine the threshold point along the smoothed *RLMPC* beyond which demand curtailments become beneficial when the smoothed *RLMPC* becomes inelastic. We can express this condition analytically as

$$\frac{d\,\bar{\rho}_n(\bar{\ell})\big|_m}{d\,\bar{\ell}} = \frac{\bar{\rho}_n(\bar{\ell})\big|_m}{\bar{\ell}},\; m = 1,2,\ldots,12;\; n = 0,1,2,\ldots,N. \tag{4.5}$$

We denote the solution of (4.5) as $\bar{\ell}_n^{\upsilon}\big|_m$ and we define the locational threshold price (*LTP*) $\bar{\upsilon}_n\big|_m$ as

$$\bar{\upsilon}_n\big|_m = \bar{\rho}_n\left(\bar{\ell}_n^{\upsilon}\big|_m\right)\Big|_m,\; m = 1,2,\ldots,12;\; n = 0,1,2,\ldots,N. \tag{4.6}$$

We use the *LTPs* $\bar{\upsilon}_n\big|_m$ to determine the basis for allowing the participation of *DRR*s in the *DAM*s and for their compensation at the *LMP* for the demand curtailments dispatched in the cleared *DAM*s. Whenever the pre-curtailment *LMP* at a particular node in the system is at or above its *LTP* $\bar{\upsilon}_n\big|_m$, all the demand-curtailment offers at that node are allowed to participate in the *DAM* for that hour. All the *DRR*s whose offers are accepted are compensated at the resulting post-curtailment *LMP* for the services provided.

In essence, the modified *NBT* does not change the way the *DAM*s are run by the *IGO* environment. The use of the *LTP* still requires that the *DAM*s be run twice: once without *DRR* participation and a second time with the *DRR* offers.

Instead of a single monthly threshold price, we use a different threshold at each node to identify those which can provide demand curtailment services and be compensated at the post-curtailment *LMP*s.

A second issue we identified was the fact that under the rules of Order No. 745, there may be nodes in the power system that experience higher total post-curtailment payments even though they are non-*DRR* participants. As the basis of *FERC* decisions in Order No. 745 was to ensure that no participant is worse off due to *DRR* curtailments in the post-curtailment outcomes than in the pre-curtailment outcomes, a required step in the modified *NBT* is to ascertain that this condition is indeed met. We introduce a second modification in the *FERC NBT* to ensure that the "no participant is worse off" condition is met.

For each hour *h*, we collect the nodes that experience higher post-curtailment *LMP*s than pre-curtailment *LMP*s and construct the set

$$N^{-}\Big|_{m,h} = \left\{ n : \left[\lambda_n' \big|_{m,h} \right]^* < \left[\lambda_n \big|_{m,h} \right]^* \right\},\ h \in \bar{H}\big|_m,\ m = 1, 2, \ldots, 12.$$

These nodes in the set $N^{-}\Big|_{m,h}$ are worse-off in the post-curtailment state and will incur in additional payments of

$$\bar{u}^{N^-}\Big|_{m,h} = \sum_{n \in N^-|_{m,h}} \left(\left[\lambda_n \big|_{m,h} \right]^* - \left[\lambda_n' \big|_{m,h} \right]^* \right) \cdot \left(\left[p_n^d \big|_{m,h} \right]^* - \left[\hat{p}_n^d \big|_{m,h} \right]^* \right), \quad (4.7)$$

where the quantity $\left[p_n^d \big|_{m,h} \right]^* - \left[\hat{p}_n^d \big|_{m,h} \right]^*$ is the net cleared demand at the node n. Equation (4.7) is a positive quantity that must be taken into account when calculating the societal costs of demand curtailments. On the other hand, the subset of nodes $N - N^- \big|_{m,h}$ enjoy a post-curtailment *LMP* that is lower than the pre-curtailment *LMP* and the total benefit enjoyed by these nodes is

$$\bar{u}^{N^+} \Big|_{m,h} = \sum_{n \in N^+|_{m,h}} \left(\left[\lambda_n' \big|_{m,h} \right]^* - \left[\lambda_n \big|_{m,h} \right]^* \right) \cdot \left(\left[p_n^d \big|_{m,h} \right]^* - \left[\hat{p}_n^d \big|_{m,h} \right]^* \right). \quad (4.8)$$

We now proceed to include the quantities in (4.7) and (4.8) in the determination of the modified societal costs and benefits of demand curtailments. The total hourly costs of demand curtailments including the payments to the *DRR*s and the extra payments incurred by all nodes $n \in N^- \big|_{m,h}$, $\bar{\zeta} \big|_{m,h}$ is

$$\bar{\zeta} \big|_{m,h} = \zeta \big|_{m,h} + \bar{u}^{N^-} \Big|_{m,h}, \quad (4.9)$$

where $\zeta \big|_{m,h}$ are the total hourly payments to the *DRR*s as defined in (2.18).

With this modification to the *NBT*, we ensure that no node is worse off in the post curtailment state than in the pre-curtailment. To account for the additional cost incurred by the nodes of $N^- \big|_{m,h}$, the benefits of the nodes in

$N - N^{-}\big|_{m,h}$ are decreased by the amount $\bar{u}^{N^{-}}\big|_{m,h}$ so as to make the nodes $n \in N^{-}\big|_{m,h}$ unaffected by the load curtailment.

We assign a fraction of $\bar{\zeta}\big|_{m,h}$ among all nodes that benefit and define the nodal demand curtailment cost $\bar{\varpi}_n^{N^{+}}\big|_{m,h}$ for $n \in N^{+}\big|_{m,h}$ as

$$\bar{\varpi}_n^{N^{+}}\Big|_{m,h} = \frac{\left(\left[\lambda'_n\big|_{m,h}\right]^{*} - \left[\lambda_n\big|_{m,h}\right]^{*}\right)\cdot\left(\left[p_n^d\big|_{m,h}\right]^{*} - \left[\hat{p}_n^d\big|_{m,h}\right]^{*}\right)}{\sum\limits_{n\in N^{+}|_{m,h}}\left(\left[\lambda'_n\big|_{m,h}\right]^{*} - \left[\lambda_n\big|_{m,h}\right]^{*}\right)\cdot\left(\left[p_n^d\big|_{m,h}\right]^{*} - \left[\hat{p}_n^d\big|_{m,h}\right]^{*}\right)}\bar{\zeta}\Big|_{m,h}. \quad (4.10)$$

We see in (4.10) that each node that benefits pays a pro-rata fraction of $\bar{\zeta}\big|_{m,h}$ that is proportional to the load that is served post-curtailment. Now, to assure that the nodes that belong to the set $N^{-}\big|_{m,h}$ are made whole, we define the nodal side payment $\bar{\varpi}_n^{N^{-}}\big|_{m,h}$ as

$$\bar{\varpi}_n^{N^{-}}\Big|_{m,h} = \left(\left[\lambda'_n\big|_{m,h}\right]^{*} - \left[\lambda_n\big|_{m,h}\right]^{*}\right)\cdot\left(\left[p_n^d\big|_{m,h}\right]^{*} - \left[\hat{p}_n^d\big|_{m,h}\right]^{*}\right),\ n \in N^{-}\Big|_{m,h}. \quad (4.11)$$

Essentially, with (4.11) we guarantee that the nodes that experienced higher *LMP*s due to demand curtailments receive compensation equal to what the increase was. If an inefficient dispatch of *DRR*s occurs then the total costs in (4.9) are socialized among the loads in the system.

4.2 Simulation Studies Using the Proposed Modified *NBT*

We now proceed to present a set of simulation study results to show the impacts of the *LTP* in the clearing of the *DAM*s. For all the simulation studies presented in this chapter, we use the same test system and set-up as provided in Chapter 3. We denote the simulation studies using the proposed modified *NBT* as: N_c^p for the cases using *ISO-NE* data and M_c^p for the cases using *MISO* data, with c as the demand response capacity. We start by discussing the differences between the nodal thresholds and the *NBT* system-wide threshold. Since now we are using the *LMP*s at each node to determine an *LTP*, the situation where a node does not meet the threshold price does not occur.

In Fig. 4.1, we show the pre- and post-curtailment *LMP*s at node 8 during the first week of May 2010 in case study N_3^p. We note that the nodal threshold $\bar{\upsilon}_8\big|_5$ is such that it allows demand curtailments to occur during this week. The system-wide threshold for this month is so high compared to the *LMP*s at this node that the *DRR*s at this location cannot participate with demand-curtailment offers. The *LTP* is a more appropriate metric for this node because it will always fall within the month's maximum and minimum *LMP*s at the node. In Fig. 4.2, we show the pre- and post-curtailment *LMP*s during the first week of May at node 116 in study case N_3^p. We note that the nodal threshold is slightly higher than the system-wide threshold.

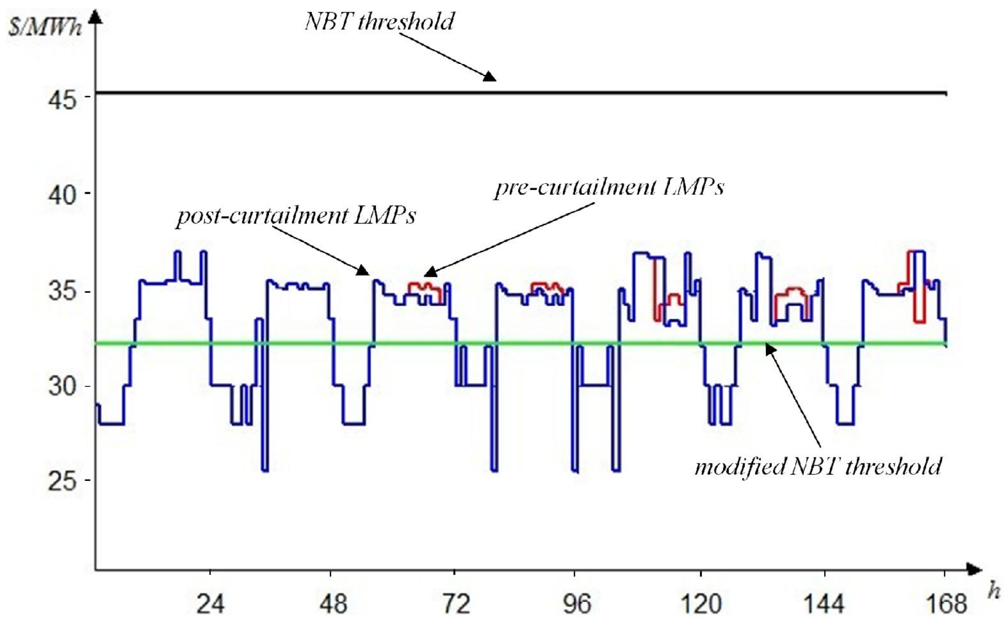

Figure 4.1: Pre- and post-curtailment *LMP*s during the week of May 1-7 at node 8 in study case N_3^p

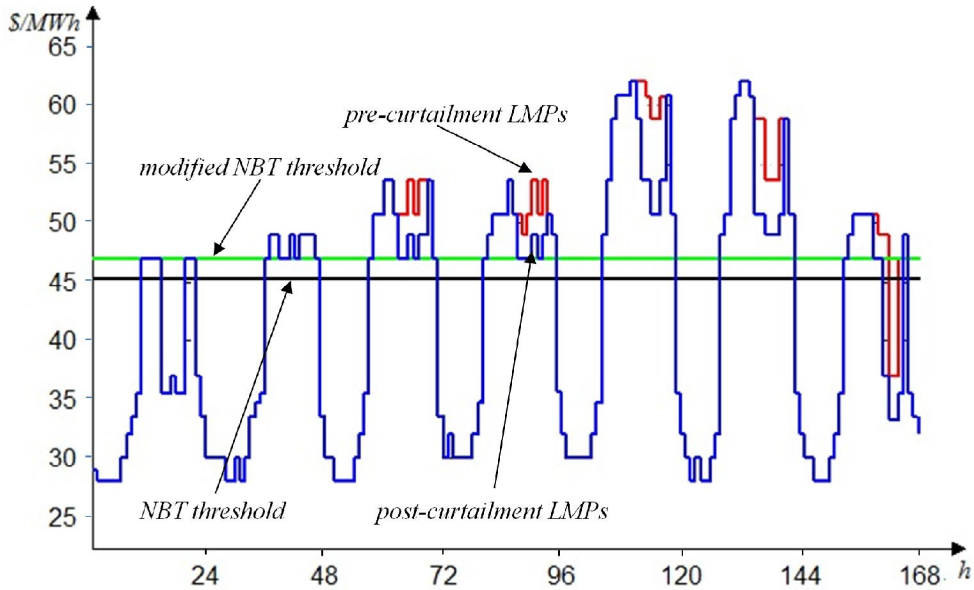

Figure 4.2: Pre- and post-curtailment *LMP*s during the week of May 1-7 at node 116 in study case N_3^p

This is the situation at the nodes that experience higher *LMP*s and higher benefits from the demand curtailments. With the *LTP* methodology, the nodes that had little or no demand response participation have a cost-effectiveness metric that is commensurate with the prices of electricity. Also, the nodes that had disproportionate demand response participation due to a low system-wide threshold have a nodal threshold that correctly captures the cost-effectiveness of demand curtailments. Next, we explore the impacts of the *LPT* methodology on the unintended consequence of the instances where the payments to the *DRR*s exceed the benefits attained.

In Table 4.1, we summarize the number of instances where the payments to the *DRR*s exceeded the benefits attained for some representative simulation studies using the *LTP* methodology. In case N_3^p, a total of 39 instances resulted in higher *DRR* payments than system benefits, which represents approximately 5.7% of the total curtailment hours. Compared to case N_3, where 17.8% of the curtailment hours resulted in extra payments due to the demand curtailments, the *LPT* methodology captured more of the hours that resulted in unintended consequences. The percentage of hours with unintended consequences is reduced for all cases with the *LPT* methodology, compared to the *FERC NBT* cases. We note that the case studies with more demand response capacity result in fewer instances of higher payments due to demand curtailments. As more MWh are curtailed, the post-curtailment *LMP*s are further reduced, which in turn mitigates the payments to the *DRR*s.

We note that with the proposed changes to the *NBT* there are still hours in which the societal costs exceed the benefits of *DRR* participation. This is due to the fact the benefits enjoyed did not mitigate payments to the *DRR*s. We note that the indices of the hours with higher costs than benefits are a subset of the same type of hours in the cases with less demand response capacity.

Table 4.1: Number of instances with extra payments due to demand curtailments for cases using *ISO-NE* data

month	number of instances where the societal costs exceed the societal benefits of *DRR* participation				
	case N_3^p	case N_5^p	case N_7^p	case N_9^p	case N_{11}^p
Jan	0	0	0	0	0
Feb	3	3	3	3	3
Mar	0	0	0	0	0
Apr	0	0	0	0	0
May	10	8	0	0	0
Jun	4	3	0	0	0
Jul	0	0	0	0	0
Aug	20	16	14	0	0
Sep	1	0	0	0	0
Oct	4	0	0	0	0
Nov	1	1	1	1	1
Dec	0	0	0	0	0
Total	43	31	18	4	4

In Table 4.2, we show the number of instances where the societal costs of *DRR* participation exceed the benefits using the *MISO* data. For all the cases using the *MISO* data there was a significant drop in the number of curtailment hours. This is to be expected because when using the *FERC NBT* the *MISO* cases had a large number of unintended consequences. As much as 66% of the curtailment hours resulted in higher payments than benefits in case M_3. In case M_3^p, the 31 instances of higher *DRR* payments than benefits represent a 20% of the total curtailment hours. With the *MISO* cases we also note that the indices of the hours with higher costs than benefits are a subset of the same type of hours in the cases with less demand response capacity.

Table 4.2: Number of instances with extra payments due to demand curtailments for cases using *MISO* data

month	number of instances where the societal costs exceed the societal benefits of *DRR* participation				
	case M_3^p	case M_5^p	case M_7^p	case M_9^p	case M_{11}^p
Jan	3	3	3	3	3
Feb	2	0	0	0	0
Mar	0	0	0	0	0
Apr	6	1	1	1	1
May	0	0	0	0	0
Jun	0	0	0	0	0
Jul	0	0	0	0	0
Aug	0	0	0	0	0
Sep	8	4	4	4	3
Oct	0	0	0	0	0
Nov	12	10	10	10	10
Dec	0	0	0	0	0
Total	31	18	18	18	17

To show the impacts of the modifications of the *NBT* made to ensure that no one is worse off we show the percentage decrease in consumer payments in the same nodes that were worse off in the cases using the *FERC NBT* as presented in Chapter 3. In Table 4.3, we see that due to the side-payment in (4.11) no node incurs in higher payments due to demand curtailments. In fact, all these nodes benefited from the curtailments. These percentages are calculated using the base case N_0.

Table 4.3: Percent decrease in buyer payments in selected nodes that were worse off with *FERC NBT* using the *ISO-NE* data

node number	percentage decrease in consumer payments				
	case N_3^p	case N_5^p	case N_7^p	case N_9^p	case N_{11}^p
1	0.80	1.03	1.20	1.39	1.57
2	0.80	1.03	1.20	1.40	1.58
3	0.80	1.03	1.20	1.38	1.56
4	0.79	1.00	1.15	1.32	1.47
6	0.80	1.03	1.20	1.38	1.55
8	0.81	1.00	1.15	1.30	1.44
11	0.81	1.04	1.22	1.41	1.59
12	0.81	1.04	1.22	1.42	1.61
13	0.80	1.05	1.23	1.43	1.64
16	0.81	1.05	1.23	1.43	1.63

On the other hand, in Table 4.4 we show the percentage decrease in consumer payments in the same nodes that benefited the most from demand curtailments under the *FERC NBT*. All these nodes continue to benefit from demand curtailments but, as expected with the modified *NBT*, these benefits are reduced due to the inclusion of the payment to the nodes that were worse off. We show the same results for the *MISO* data in Tables 4.5 and 4.6.

Table 4.4: Percent decrease in buyer payments in selected nodes that benefited with *FERC NBT* using the *ISO-NE* data

node number	percentage decrease in buyer payments				
	case N_3^p	case N_5^p	case N_7^p	case N_9^p	case N_{11}^p
42	1.76	2.71	3.50	4.23	4.98
49	1.74	2.67	3.45	4.17	4.91
54	1.75	2.68	3.46	4.18	4.92
56	1.75	2.68	3.46	4.18	4.92
59	1.75	2.68	3.47	4.19	4.93
60	1.75	2.68	3.47	4.19	4.93
62	1.75	2.68	3.47	4.19	4.93
80	1.71	2.62	3.38	4.09	4.81
90	1.72	2.62	3.39	4.09	4.81
116	1.75	2.69	3.48	4.21	4.95

Table 4.5: Percent decrease in buyer payments in selected nodes that were worse off with *FERC NBT* using the *MISO* data

node number	percentage decrease in consumer payments				
	case M_3^p	case M_5^p	case M_7^p	case M_9^p	case M_{11}^p
1	0.256	0.247	0.242	0.237	0.235
2	0.270	0.256	0.255	0.254	0.257
3	0.272	0.273	0.279	0.284	0.292
4	0.259	0.251	0.246	0.240	0.238
6	0.272	0.273	0.279	0.284	0.293
7	0.268	0.262	0.257	0.253	0.252
8	0.273	0.261	0.263	0.265	0.270
11	0.290	0.287	0.300	0.312	0.328
12	0.263	0.268	0.275	0.282	0.291
117	0.275	0.273	0.282	0.289	0.300

Table 4.6: Percent decrease in buyer payments in selected nodes that benefited with *FERC NBT* using the *MISO* data

node number	percentage decrease in consumer payments				
	case M_3^p	case M_5^p	case M_7^p	case M_9^p	case M_{11}^p
42	0.252	0.334	0.401	0.449	0.505
49	0.260	0.346	0.417	0.470	0.530
54	0.260	0.346	0.418	0.470	0.531
56	0.252	0.334	0.401	0.449	0.505
59	0.258	0.344	0.415	0.467	0.527
60	0.259	0.346	0.417	0.470	0.530
62	0.258	0.344	0.415	0.467	0.528
80	0.241	0.312	0.369	0.408	0.455
90	0.241	0.312	0.369	0.408	0.455
116	0.252	0.331	0.397	0.443	0.498

4.3 Comparison of the *NBT* and the Proposed Modified *NBT*

Our goal is to propose modifications to the *NBT* without changing its nature and providing additional considerations to ensure efficiency of load curtailment services. In this section, we provide an overview of the modifications. The modifications of the *FERC NBT* were made based on the issues identified in Chapter 3. The modifications introduced are:

- use of more appropriate data, i.e., rather than use the offer set for the entire period we only use the on-peak *LMP*s,
- determination of a location-dependent threshold price, and
- the explicit assurance that a demand curtailment does not negatively impact any load.

The rationale behind using on-peak *LMP*s instead of the offers is to explicitly include the impacts of transmission congestion. The failure to incorporate the impacts of transmission congestion in the determination of the threshold price may lead to the setting of an inappropriate threshold price. Since the *LMP*s explicitly account for the congestion impacts and the offer prices, the determination of the threshold price on the basis of the *LMP*s overcomes this problem. Furthermore, as demand curtailments rarely occur during off-peak hours, we restrict the data to on-peak *LMP*s and so we eliminate the reliance on the off-peak data so as not to distort the determination of the location-dependent threshold price towards the lower *LMP*s.

In Chapter 3, we identified that because of the non-nodal nature of the *FERC NBT*, some nodes may not participate in the *DAM* to be compensated for demand curtailments due to the high threshold price. On the other hand, the monthly system-wide threshold may be so low that a node may have demand curtailments much more often than others. In other words, a system-wide threshold does not measure properly when a demand curtailment is appropriate in a node by node basis. With the proposed modifications, each node has its own monthly threshold price determined from the actual *LMP*s for the same month in the previous year and provides an appropriate nodal signal in the setting of the threshold price on a nodal basis.

We assure that no one is worse off with the introduction of a side payment to the nodes that incur in higher payments due to the demand curtailments. As a result, the test ensures that only in those cases when the societal benefits exceed the societal costs, are the *DRR*s compensated at the *LMP*.

We start out with the scheme to determine nodal threshold prices for *DRR* participation. The modifications are in the "spirit" of Order No. 745, i.e., analogous to the process deployed for determining the monthly threshold price, and we introduce the explicit consideration of locational topological information into the *NBT*. In this way, we are able to incorporate transmission congestion effects into the determination of the threshold at each node. For each month and node we determine a locational threshold price (*LTP*) using the *LMP* data of the same month in the previous year. Since *DRR* participation is very limited during hours with low *LMP*s, we only consider on-peak *LMP*s during the weekdays to determine the *LTP*s. We construct a representative *LMP* curve for each node of the system, we use the smoothing techniques for this curve and then we determine the nodal threshold by finding the point on the curve where (2.3) condition is met.

4.4 Summary

In this chapter, we presented a set of three proposed modifications to the *FERC NBT* that address the issues identified in Chapter 3. These modifications take into account transmission congestion in the determination of the threshold price and ensure that no one is worse off in the post-curtailment state. We also presented results from simulation runs using the proposed modified *NBT* showing the lessening in the impacts due to the instances with higher societal costs than benefits of *DRR* participation and the assurance that no node incurs higher post-curtailment payments.

CHAPTER 5

CONCLUSIONS

In this thesis, we study the impacts of demand curtailments in the *DAM*s under the procedure and the accompanying compensation scheme mandated by the *FERC* in Order No. 745. By including the *FERC NBT* in the extended transmission constrained market model with the explicit representation of the *DRRs*, we identify and analyze certain unintended consequences that result from the nature of the determination of the threshold price that we observed in our extensive simulation studies of the impacts of *FERC* Order No. 745. Due to the lack of consideration of transmission-grid effects for the *FERC NBT*, the system-wide threshold may not be the appropriate metric to determine the dispatch of *DRR*s in all nodes of the system. Due to congestion patterns and location, the *LMP*s at some nodes may be lower than the monthly threshold price at all hours of the month. This situation does not allow any demand response participation at these nodes. On the other hand, nodes that experience higher *LMP*s may meet the monthly threshold at all hours of the month. We also identify that under the *FERC*'s scheme, there are instances in which the incentive payments to the *DRR*s exceed the benefits of the entire system. We also identify that there are nodes in the system that incur higher payments in the post-curtailment state than in the pre-curtailment state even though they make no modifications of their loads. These affected nodes consistently have higher post-curtailment *LMP*s due to the fact that demand curtailments made at other nodes modify the congestion patterns in the system.

We propose modifications to the *NBT* so as to explicitly address the identified issues. The modifications are in three principal areas – data usage, explicit consideration of transmission system in the determination of the threshold price and an additional test to guarantee that no buyer is worse off in the post-curtailment state than in the pre-curtailment state. We propose to use on-peak *LMP*s instead of the offer data to construct a representative *LMP* curve. The use of the *LMP* data provides a more meaningful basis for the determination of the threshold price. We propose the replacement of the system-wide threshold price by node-specific threshold prices at each node to explicitly account for transmission considerations. To guarantee that no load incurs in higher post-curtailment payments than in the pre-curtailment state, we propose the introduction of a simple test to verify that this criterion is met. The proposed modifications keep both the spirit and nature of the *NBT* intact while addressing the issues identified in our studies.

To test the ability of the proposed modifications to address the identified unintended consequences, we run simulation studies with the proposed modified *NBT* and compare them with the *FERC NBT* study cases. The results of the testing we performed indicate that the instances of higher post-curtailment purchase payment are reduced by at least an order of magnitude and in each case every node in the system is assured that it is not worse off due to demand curtailments.

Due to the increasing use of renewable energy sources, an interesting extension of the work presented in this thesis is the inclusion of such generation technologies in the studies. Adding the variability and uncertainty of renewable energy sources in the study of the impacts of demand curtailments would give insight into how the *NBT* and the proposed modified *NBT* perform under such conditions. Another extension is the study of the impacts of demand curtailments under contingency conditions. A study of how well the proposed modified *NBT* performs in the event of losing a line is of great interest.

APPENDIX A

DETAILS OF THE TEST SYSTEM

For the studies presented in this thesis, we use the modified *IEEE* 118-bus system. This system, which is based on the *ISO-NE* network, has 54 generators and 186 lines. We use load shapes from *ISO-NE* and *MISO* from the year 2010. For each hour of the year, we aggregate the load and then scale it and distributed proportionally among the nodes of the test system. The peak load of the test system has a value of 9,600 MW. We assume that the demand of the buyers is a fixed quantity and is not responsive to price. In Fig. A.1 we show the scaled load for the first two weeks of the month of July.

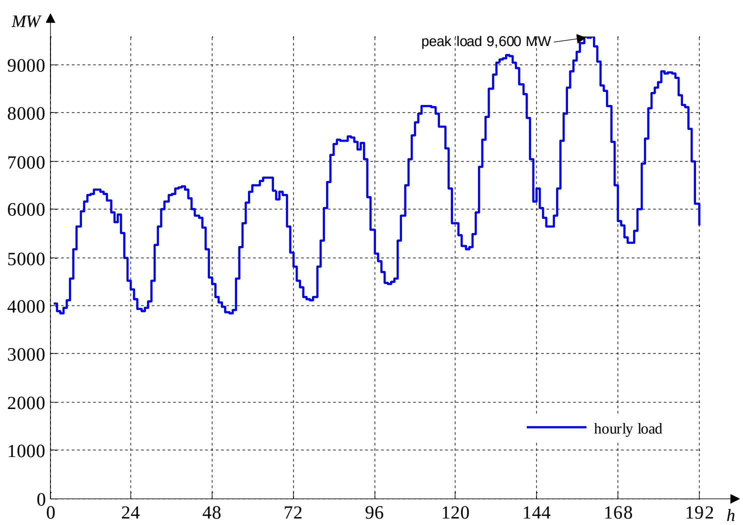

Figure A.1: Scaled hourly load for the *IEEE* 118-bus test system during the first week of July 2010

We make use the *ROC*s of each month to construct monthly offer curves for the test system. We distribute the prices and quantities of the monthly *ROC* among the 54 generators so as to construct an offer curve for the test system that mimics the shape of the original *ROC*. We then scale this offer curve to the test system level. By doing this, we take into consideration the seasonal variations of the offer curve. In Fig A.2 we show the *ROC* and the test-system offer curve (before scaling) during the month of July.

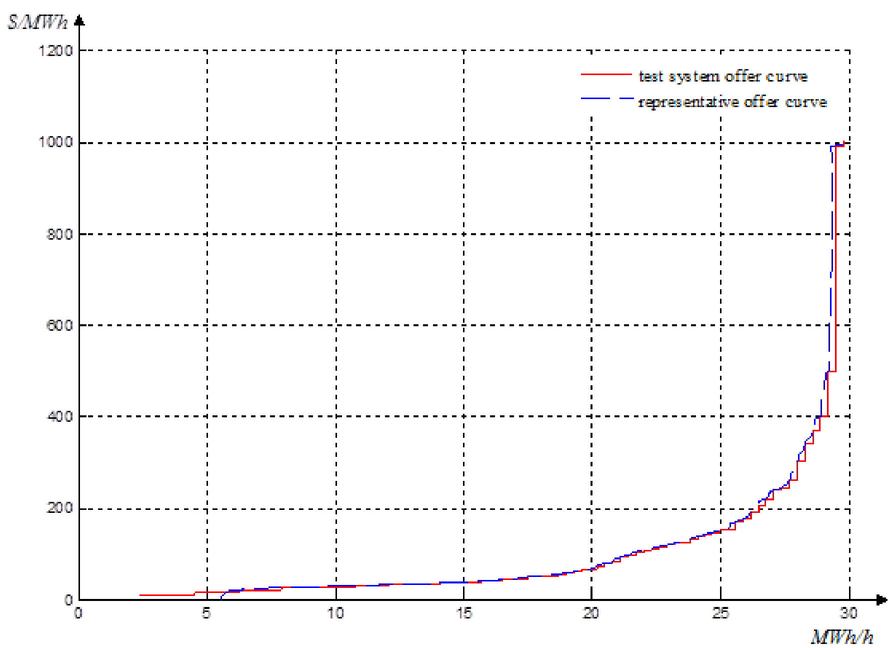

Figure A.2: *ROC* and test-system offer curve during the month of July

To determine the monthly threshold prices we apply the procedure described in Chapter 2 to the test system offer curves. In Table A.1 we show the monthly threshold prices for both the *ISO-NE* and *MISO* data.

Table A.1: Monthly threshold prices

month	monthly threshold prices	
	ISO-NE data	*MISO* data
1	114.74	77.81
2	105.69	74.51
3	51.16	44.58
4	39.01	54.85
5	45.27	59.77
6	48.21	49.56
7	47.49	44.20
8	34.63	49.96
9	31.06	46.55
10	26.18	42.66
11	54.74	59.81
12	82.32	63.52

REFERENCES

[1] "Energy Policy Act of 2005," United States Public Law 109-58. August 8, 2005. [Online]. Available: http://www.gpo.gov/fdsys/pkg/ PLAW-109publ58/pdf/PLAW-109publ58.pdf

[2] *FERC* Staff, "Assessment of demand response and advanced metering," Federal Energy Regulatory Commission, Tech. Rep., December 2008. [Online]. Available: http://www.ferc.gov/legal/staff-reports/12-08-demand-response.pdf

[3] Federal Energy Regulatory Commission, "Wholesale competition in regions with organized electric markets," Washington DC, October 17, 2008, Docket No. RM07-19000, Order No. 719. [Online]. Available:http://www.ferc.gov/whats-new/comm-meet/ 2008/ 101608/E-1.pdf

[4] Federal Energy Regulatory Commission, "Demand response compensation in organized wholesale energy markets," Washington DC, March 29, 2010, Supplemental Notice of Proposed Rulemaking, Docket No. RM10-17-000. [Online]. Available: http://www.ferc.gov/EventCalendar/Files/20100802113647-RM10-17-000.pdf

[5] Demand Response Supporters, "Reply comments of the demand response supporters," Washington DC, August 10, 2010, Docket No. RM10-17-000. [Online]. Available: http://www.nera.com/nera-files/FERC_Reply_Comments_Kahn_08.30.10.pdf

[6] A. E. Kahn, Affidavit attached to "Reply comments of the demand response supporters," Washington DC, August 10, 2010, Docket No. RM10-17-000. [Online]. Available: http://www.ferc.gov/whats-new/comm-meet/ 2008/101608/E-1.pdf

[7] Federal Energy Regulatory Commission, “Demand response compensation in organized wholesale energy markets,” Washington DC, March 15, 2011, Docket No. RM10-17000, Order No. 745, pp. 2, pp. 63, pp. [Online]. Available: http://www.ferc.gov/EventCalendar/Files/20110315105757-RM10-17-000.pdf

[8] J. Falk, “Paying for demand-side response at the wholesale level,” *The Electricity Journal*, vol. 23, no. 9, pp. 13-18, November 2010.

[9] W. Hogan, “Demand response compensation, net benefits and cost allocation: comments,” *The Electricity Journal*, vol. 23, no. 9, pp. 19-24, November 2010.

[10] R. Borlick, “Paying for demand-side response at the wholesale level: the small consumer’s perspective,” *The Electricity Journal*, vol. 24, no. 9, pp. 8-19, November 2011.

[11] R. Pierce, “A primer on demand response and a critique of FERC Order No. 745,” *Journal of Energy and Environmental Law*, vol. 3, no. 1, pp. 102-109, January 2012.

[12] Market Surveillance Committee of the California ISO, “Opinion on economic issues raised by *FERC* Order No. 745,” June 6, 2011. [Online]. Available: http://www.caiso.com/2b97/2b97a0bb6ef70.pdf

[13] Midwest Independent Transmission System Operator, Inc., “Order No. 745 compliance filing,” August 19, 2011, Docket No. ER11-___-000. [Online]. Available: https://www.midwestiso.org/Library/Repository/Tariff/FERC%20Filings/2011-08-19%20Docket%20No.%20ER11-4337-000.pdf

[14] ISO New England Inc., “Order No. 745 compliance filing,” August 19, 2011, Docket No. ER11-4336-001. [Online]. Available: http://www.iso-ne.com/regulatory/ferc/filings/2011/aug/er11_4336_000_prd_filing.pdf

[15] Midwest Independent Transmission System Operator, Inc., "Net benefits test for demand response compensation," August 11, 2011. [Online]. Available: https://www.midwestiso.org/Library/Repository/Meeting%20Material/Stakeholder/DRWG/2011/20110829/DRWG%20Draft%20Net%20Benefits%20Analysis%20Paper.pdf

[16] California ISO, "Demand Response Net Benefits Test," California ISO Final Proposal, June 29, 2011. [Online]. Available: http://www.caiso.com/Documents/FinalProposal-DemandResponseNetBenefitsTest.pdf

[17] PJM Interconnection, LLC, "FERC Order 745: the net benefits test", DOCS# 642037, 2011. [Online]. Available: http://www.pjm.com/~/media/committees-groups/committees/mic/20110510/20110510-item-08b-order-745-net-benefits-test.ashx

[18] The Brattle Group, "Quantifying demand response benefits in PJM," prepared for PJM Interconnection, LLC and Mid-Atlantic Distributed Resources Initiative (MADRI), January 29, 2007.

[19] R. Walawalkar, S. Blumsack, J. Apt, and S. Fernands, "Analyzing PJM's economic demand response program," in *2008 IEEE Power and Energy Society General Meeting - Conversion and Delivery of Electrical Energy in the 21st Century*, pp. 1-9, July 2008.

[20] D. S. Kirschen, "Demand-side view of electricity markets," *Transactions on Power Systems*, vol. 18, no. 2, pp. 520-527, May 2003.

[21] P.I. Caro-Ochoa, "Evaluation of transmission congestion impacts on electricity markets," M.S. thesis, Department of Electrical and Computer Engineering, University of Illinois at Urbana-Champaign, 2003.

[22] A. S. Kowli, "Assesment of Variable Effects of Systems with Demand Response Resources," M.S. Thesis, Department of Electrical and Computer Engineering, University of Illinois at Urbana-Champaign, 2009.

[23] A. Borghetti, G. Gross, and C. A. Nucci, "Auctions with explicit demand-side bidding in competitive electricity markets," in *The Next Generation of Electric Power Unit Commitment Models*, vol. 36, Norwell, MA: Kluwer Academic Publishers, 2001, pp. 53-77.

[24] C. L. Su and D. Kirschen, "Quantifying the effect of demand response on electricity markets," *IEEE Transactions on Power Systems*, vol. 24, no. 3, pp. 1199-1207, August 2009.

[25] A.J. Wood and B.F. Wollenberg, *Power Generation, Operation and Control*, 2nd ed. New York, NY: John Wiley and Sons, Inc., 1996.

[26] G. Gross, ECE 530 Lecture notes, *Analysis Techniques for Large-Scale Electrical System*, 2012. [Online]. Available: http://courses.ece.illinois.edu/ece530

[27] G. Gross, ECE 573 Lecture notes, *Power System Operation and Control*, 2012. [Online]. Available: http://courses.ece.illinois.edu/ece573

[28] "Power systems test case archive," University of Washington Department of Electrical Engineering. [Online]. Available: http://www.ee.washington.edu/research/pstca/